SELF-GENERATION INCENTIVE PROGRAM

2023 SGIP IMPACT EVALUATION

Submitted to:
Pacific Gas and Electric Company
SGIP Working Group

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1 EXECUTIVE SUMMARY

The Self-Generation Incentive Program (SGIP) was established in 2001 and provides financial incentives for the installation of behind-the-meter (BTM) distributed generation and energy storage technologies that meet all or a portion of a customer's electricity needs. The program is managed by Program Administrators (PAs) representing California's major investor-owned utilities (IOUs). The California Public Utilities Commission (CPUC) provides oversight and guidance on the SGIP. Historically, the SGIP has been solely funded by California's ratepayers. However, in 2023, Decision 24-03-071 implemented Assembly Bill (AB) 209 which allocated state funding from the Greenhouse Gas Reduction Fund (GGRF) to the SGIP. This will be incorporated into the program starting in 2025.

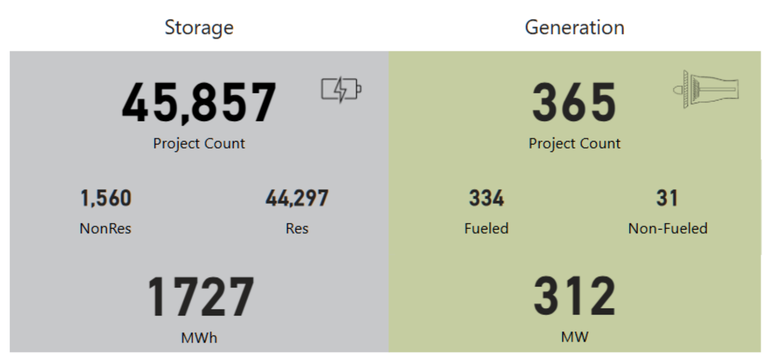
Measurement and Evaluation

SGIP goals, eligibility requirements and incentive levels have changed in the past 20 years in alignment with California's evolving energy policies. Ongoing evaluation reports serve as an important feedback mechanism to assess the SGIP's effectiveness and ability to meet those evolving goals. CPUC Decision 19-09-027 required the SGIP PAs to develop a Measurement and Evaluation (M&E) Plan for the SGIP covering 2021-2025. That plan was approved in May of 2022, and finalized in January of 2023**. The primary objective of this study is to satisfy the requirements of the 2021-2025 M&E Plan by evaluating the performance of incentivized SGIP systems operating during calendar year 2023.**

Evaluation Population

The SGIP population subject to evaluation encompasses all cumulative projects since program inception receiving an upfront SGIP incentive through December 31, 2023, and remaining within their required permanency period[1] as specified by the Program Handbook. The evaluation population includes **46,222 SGIP projects** representing roughly **1,727 MWh of energy storage rebated capacity and 312 MW of generation equipment incentivized capacity**.

FIGURE 1-1: SGIP 2023 EVALUATION POPULATION



[1] Permanency period refers to the length of time an SGIP incentivized technology is required to abide by program rules (usually 10 years for most technologies).

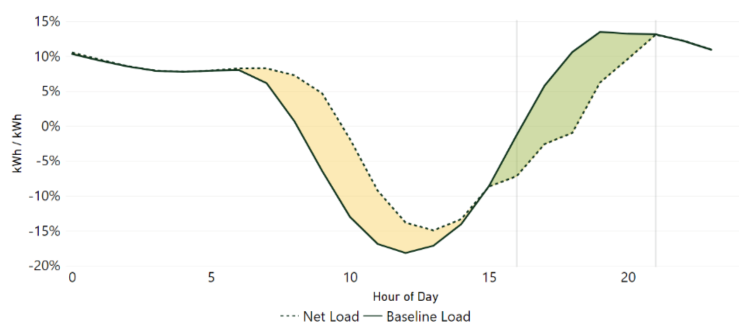
While over 97% of the SGIP storage population are residential projects, the program capacity is roughly split between the residential and nonresidential sectors. Energy storage technologies are installed across multiple budget categories and facility types. Nonresidential systems range in size from roughly 10 kWh to over 5,000 kWh, with an average capacity of 565 kWh. Residential systems generally range from 10 kWh to 40 kWh, with an average capacity of 19 kWh. Electric-only fuel cell projects account for a third of the total rebated generation capacity.

Evaluation Approach

This evaluation examines the performance of SGIP systems by quantifying the observed impacts of systems during 2023. Verdant collected metered generation data, storage charge and discharge data, and customer electric load profiles for SGIP participants. Some of the results discussed in this report are developed to better understand the efficiency or utilization of SGIP systems during 2023. Some impacts require additional assumptions about what a customer's electricity consumption would have been had they *not* installed the SGIP system. These assumptions describe an unobservable, counterfactual, non-SGIP baseline which we compare to observed electricity consumption to estimate impacts of the SGIP system at the utility meter.

The calculation of energy storage impacts, for example, is illustrated in the inset figure depicting average hourly delivered load on summer weekdays, along with vertical lines depicting the 4pm – 9pm on-peak period. If a customer is discharging their battery, they are reducing the need to service load from the grid so observed net load is lower than baseline net load (green shaded area). When a customer is charging the battery, they are increasing their load relative to a baseline of no storage (yellow shaded area). A customer could realize bill savings relative to the counterfactual if discharge occurred during high-priced hours (4 pm – 9pm) and charging occurred during lower-priced hours.[2] Furthermore, systems could provide greenhouse gas (GHG) emissions reductions if

FIGURE 1-2: COMPARING BASELINE LOAD TO OBSERVED LOAD



2 This is referred to as time-of-use (TOU) energy arbitrage. Billed energy savings are realized when the total dollars saved from discharging exceeds the total dollars incurred from charging the system, along with any energy losses associated with roundtrip efficiency.

the emissions *avoided* during storage discharge are greater than the emissions *increases* during storage charging.

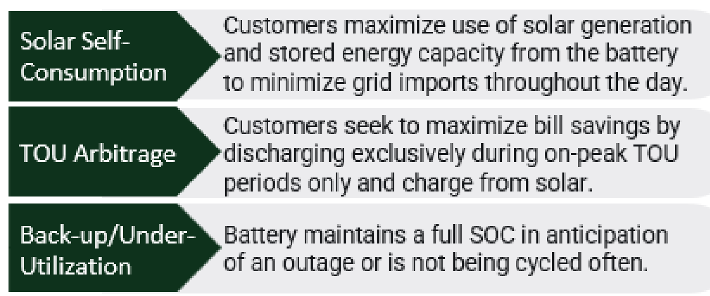
Evaluation Findings, Conclusions and Recommendations

Below we present key findings and conclusions from this evaluation based on metered data collected from a representative sample of residential and nonresidential customers. Where possible, we also provide recommendations that could inform future policy and program design. Many of these findings reveal how storage behavior during 2023 was meeting or falling short of SGIP goals and objectives. In-depth findings and analyses can be found in Section 4 and Section 5 of this report.

Storage Dispatch Behavior

Verdant evaluated a sample of 2,077 residential energy storage systems (5% of the population). **Solar PV-paired residential energy storage systems represented roughly 99% of those installations by the end of 2023**. Solar PV-paired residential energy storage systems are generally conducting 1) solar self-consumption (64% of sampled projects), 2) TOU energy arbitrage (30%) without export or with export – either regularly or exclusively during specific times like a demand response event, 3) under-utilization or back-up – **6% of systems are in back-up mode and maintaining a full state-of-charge (SOC)** in anticipation of an outage or are not being cycled often – both of which don't ascribe to program rules. We also **observe some systems paired with PV conducting TOU arbitrage but not charging from solar**[3] (3% of PV Paired systems). These systems charge overnight, perhaps to take advantage of relatively lower off-peak electric vehicle (EV) billed rates. Standalone systems are conducting TOU arbitrage – discharging the battery exclusively on peak and charging overnight. **Performance of under-utilized, standalone, and PV paired systems charging overnight results in GHG emissions increases.**

FIGURE 1-3: TYPICAL RESIDENTIAL OPERATING MODES



[3] The Federal Investment Tax Credit (ITC) was sunset in 2023, but battery storage systems were eligible for the ITC if they were paired with on-site generation like solar PV and charged from that renewable generation at least 75% of the time throughout the year. The SGIP also gives priority to projects charging a minimum of 75% from on-site renewables that don't claim the ITC. Under the new Inflation Reduction Act (IRA), the ITC has been updated and expanded for energy storage. Minimum charging requirements from clean on-site renewable generation have been removed, however.

Verdant evaluated 1,211 nonresidential energy storage systems (78% of the population). Systems co-located or paired with PV represented roughly 35% of those installations by the end of 2023. The remaining 65% represents standalone energy storage systems. Nonresidential storage performance is guided by similar principles and economics, but customer bill rate structure (monthly, on-peak, daily demands charges and TOU energy charges), site-specific power demands and differing load shapes create a more heterogeneous collection of dispatch profiles than the residential sector. Furthermore, nonresidential systems are also installed across a variety of building types – offices, retail, grocery stores, industrial facilities, electric vehicle (EV) charging stations, and public utilities like wastewater treatment plants. Despite these differences, **PV paired nonresidential systems are generally charging from on-site solar and both standalone and PV paired systems are discharging on-peak.**

Greenhouse Gas Emissions

CPUC D. 19-09-001 guided the development of a GHG signal to assist SGIP technologies optimize performance and reduce GHG emissions. The marginal grid GHG emissions values used to calculate environmental impacts were prepared by WattTime.[4] The data sources and analytic methodology used by WattTime are consistent with the Avoided Cost Calculator (ACC) and are approved by the CPUC. The signal calculates the marginal emissions per kWh of different generation sources (natural gas-fired power plant or renewable generation) using real-time CAISO Locational Marginal Prices (LMP) and other inputs. For energy storage systems to reduce emissions, the emissions *avoided* during storage discharge must be greater than the emission increases during storage charging. In other words, SGIP storage systems must charge during “cleaner” grid hours and discharge during “dirtier” grid hours to achieve GHG reductions.

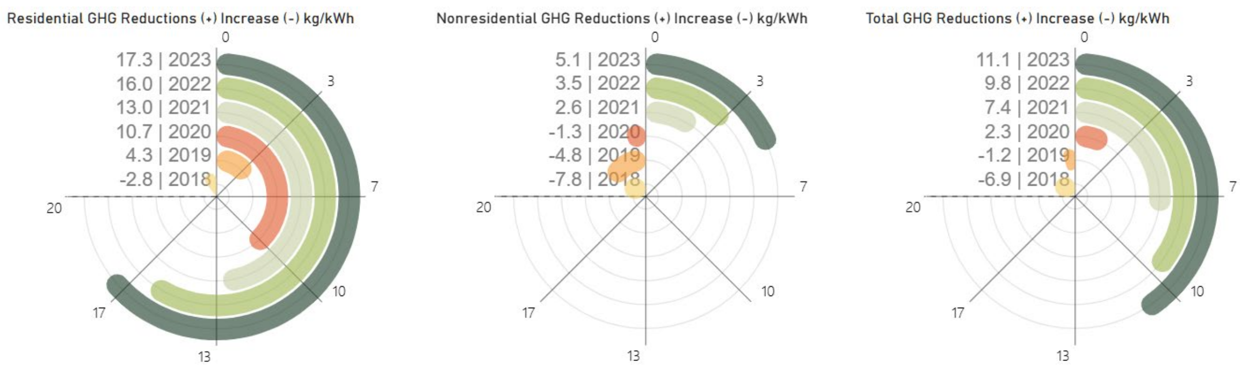
Residential *and* nonresidential energy storage systems, alone and combined, contributed to a net reduction in GHG emissions in 2023 (Section 4.4.1 and 4.6). The combined GHG reductions across sectors totaled 19,094 metric tons (MT). This follows a trend first observed in 2020 in the residential sector and at the program level, despite emissions increases from the nonresidential sector in that year. Figure 1-4 plots the decrease (+), moving clockwise from zero, or increase (-), moving counterclockwise, in emissions for each customer sector – along with the total program impact – from the past six Impact Evaluations (2018-2023). Residential fleet reductions were first observed in 2019 and have increased with each successive evaluation – from **an average reduction of 4.3 kilograms (kg) for each kWh of capacity in 2019 to a reduction of 17.3 kg for each kWh of capacity in 2023**.

GHG emissions reductions have also **improved in the nonresidential sector during the past three evaluations – with emissions reductions of 2.6 and 3.5 kg for each kWh of capacity in 2021 and 2022,**

4 https://sgipsignal.com/

respectively, increasing to 5.1 kg per kWh of capacity in 2023. An increasing share of PV paired systems charging from on-site solar and more focused on-peak discharging from more recently incentivized systems have contributed to that improvement. Some facility types like electric vehicle charging stations, schools, and critical facilities incentivized via the Equity Resiliency Budget (ERB) provide substantial emissions reductions, given the timing, magnitude and duration of charge and discharge (see Figure 4-123, Figure 4-124, and Figure 4-141).

FIGURE 1-4: STORAGE GHG EMISSIONS IMPACTS BY YEAR AND SECTOR (KG/KWH, REDUCTION (+) INCREASE (-))



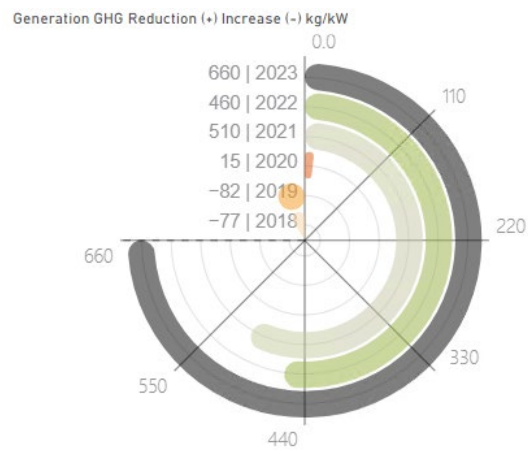
Sampled residential storage systems paired with on-site PV *and* charging from PV *decreased* emissions by over 19 kg per kWh of capacity, while standalone systems and PV-paired systems charging overnight increased emissions by 5 kg and 2 kg per kWh of capacity, respectively (Section 4.4.1). While standalone or paired systems may exhibit the same discharge behavior – to satisfy an energy arbitrage opportunity or for self-consumption – solar pairing plays an essential role in dictating when a system charges. Systems paired with on-site solar and charging from that solar provide benefits not realized by systems charging from the grid overnight. **From a GHG perspective, the value of charging during PV generating hours cannot be overstated.** SGIP energy storage systems are discharged in late afternoon and early evening when retail electricity rates are higher and on-site generation and grid-level renewable generation wanes – times that coincide with high marginal emission periods and billed on-peak hours. The emissions differentials between charging overnight and discharging on-peak are not sufficient to realize emissions reductions like observed with PV paired systems charging from on-site PV during much lower emissions hours. ***We recommend that the CPUC explore ways to ensure that standalone systems achieve GHG reductions, such as requiring that they follow the SGIP GHG signal or real-time pricing signals. Furthermore, policies and rate structures developed to promote EV home charging overnight should be considered alongside SGIP program goals of reducing GHG emissions to ensure the motivations of one policy don't adversely affect those of the other.***

Sampled nonresidential systems paired with PV reduced emissions in 2023 by roughly 14 kg per kWh of capacity (Section 4.4.1). Emissions reductions for PV paired systems were realized across all facility types.

Standalone nonresidential systems reduced emissions in 2023 by 3 kg per kWh of capacity. More recent installations of longer duration batteries installed through the Equity Resiliency Budget (ERB) are conducting arbitrage and reducing emissions at the expense of the non-coincident peak demand reductions where we observe subsequent charging “snapback” associated with demand shaving. Furthermore, EV charging stations – which are standalone – are discharging roughly 65% of capacity daily during summer on-peak hours. Charging is reserved for morning hours, much like observed by systems paired with on-site PV.

Generation systems provide the vast majority of GHG emissions reductions in 2023 (Section 4.4.2). Although generation systems comprise less than 1% of the systems installed in the SGIP, they reduced emissions by 660 kg per kW of rebated capacity throughout 2023. Renewable fueled systems capturing methane that would otherwise be vented into the atmosphere contributed to the greatest avoided GHG impact, followed by renewably fueled systems with a flared baseline and non-fueled systems. Non-renewable Gas Turbines also reduced emissions, due to their high rates of heat recovery. **These reductions are highly dependent on marginal emissions rates built into the SGIP GHG signal.**[5] While the SGIP generation population has drastically changed in recent years, much of the variation in Figure 1-4 stems from changes made to assumptions in the calculation of GHG signal values, between the differing versions of the Avoided Cost Calculator. However, the driver of the increase in emissions reductions impacts between the last report (2021-2022) and the current report (2023) has to do with the fact that almost 60 older generation systems, many of them underperforming, have now passed their permanency period and dropped out of the program, so the relative impacts of the remaining systems are higher than in 2022.

FIGURE 1-5: GENERATION GHG IMPACTS



System Utilization and Grid Needs

As a load shifting technology, BTM storage can provide grid benefits if the timing and magnitude of storage discharge aligns with periods of grid stress and coincident peak demand while system charging is left to less critical times. Utility marginal costs and grid constraints are generally highest during on-peak hours, which are captured with TOU on-peak periods in California (generally 4pm – 9pm). Conversely, storage

[5] Additional details on these updates can be found in 'SGIP GHG Signal Update', WattTime. Self-Generation Incentive Program Fourth Quarterly Workshop, December 13, 2021. https://www.selfgenca.com/documents/workshops/2021/q4

charging is best left to off-peak and super off-peak time periods when retail rates are lower, as are utility avoided costs, marginal emissions, and grid constraints.

Renewably fueled and non-fueled generation technologies provide consistent, low emission generation throughout the year, and have provided additional capacity during times of grid constraints. California witnessed significant energy constraints during 2020, and in response, one fuel cell manufacturer, which has incentivized most of the all-electric fuel cell capacity in the SGIP, ran an initiative to export significant energy to help relieve the strain on the grid using combustion-free, fuel flexible technologies. These changes still appear evident, with many of these systems exporting a large percentage of their load.

Residential and nonresidential battery systems are not discharging the total capacity of the system regularly and many residential customers are limiting discharge to maintain net zero load rather than exporting (Section 4.2.1). This finding is intuitive – if customers are already abiding by SGIP rules for round trip efficiency, utilization and GHG reductions – they may also want to have reserve energy in the event of an outage. Furthermore, frequent full discharge cycling may not be advantageous from a battery engineering, effective useful life, or warranty perspective. However, there is considerable untapped potential for Resource Adequacy (RA), Emergency Load Reduction Program (ELRP), and other grid benefits if additional battery capacity is deployed in response to grid needs and/or price signals. ***The CPUC, through the DER Futures Initiative, is currently exploring ways to encourage additional battery utilization through enrollment in virtual power plants (VPP), participation in real-time rates, or other mechanisms which encourage demand flexibility and grid support while also safeguarding resiliency benefits. We recommend that findings from the DER Futures analysis be considered in revisions of the SGIP or in development of future California DER policies.***

Solar PV paired residential storage discharges roughly 42% of system kWh capacity daily throughout summer weekdays, and standalone systems discharge about 14% of available capacity (Section 4.2.1). Most of that discharge occurs during the 4pm – 9pm on-peak hours (60% for PV paired systems and 71% for standalone systems). On-peak hours, when retail energy rates are highest, provide the greatest opportunity for customers to realize billed energy savings. If a residential customer is discharging any percentage of energy outside this period, this suggests that bill reductions may not be the primary driver or system operating mode. In fact, we observe self-consumption as the most prominent operating mode for residential storage at a fleet level. Since systems in self-consumption mode are limited by underlying customer load, hourly discharge ranges from 1% to 6% of system kWh capacity depending on the month (Figure 1-6). ***We recommend that the CPUC explore ways to encourage more targeted dispatch that emphasizes the importance of discharging batteries (and reducing load) during on-peak hours rather than daily self-consumption.***

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FIGURE 1-6: RESIDENTIAL STORAGE DISCHARGE AND CHARGE KWH PER KWH CAPACITY

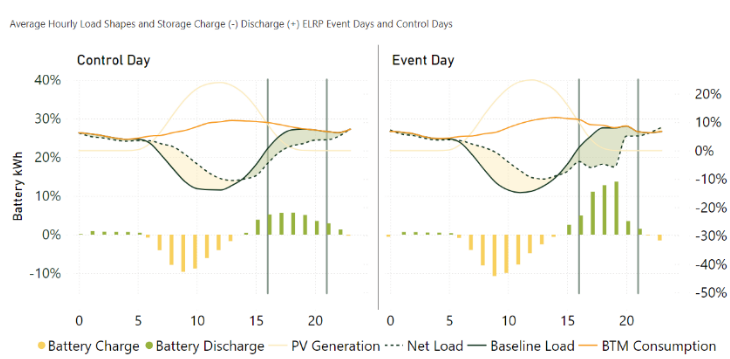
Average Hourly Residential PV Paired Net Discharge kWh / kWh Capacity (Charging from Solar)
BY MONTH, HOUR

Month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
January	0%	0%	0%	0%	0%	0%	0%	-0%	-2%	-4%	-6%	-6%	-5%	-3%	-1%	0%	3%	4%	5%	3%	3%	1%	1%	1%
February	1%	0%	0%	0%	0%	0%	0%	-0%	-3%	-6%	-7%	-7%	-5%	-3%	-2%	-0%	3%	5%	6%	4%	3%	2%	1%	1%
March	0%	0%	0%	0%	0%	0%	1%	-0%	-3%	-5%	-7%	-6%	-5%	-3%	-2%	-1%	2%	3%	5%	4%	3%	2%	2%	1%
April	1%	1%	1%	1%	1%	1%	1%	-0%	-3%	-7%	-9%	-8%	-5%	-3%	-1%	-0%	2%	3%	4%	5%	4%	3%	2%	2%
May	1%	1%	1%	1%	1%	1%	1%	-1%	-3%	-6%	-7%	-7%	-5%	-4%	-2%	-1%	2%	3%	4%	4%	4%	3%	2%	2%
June	1%	1%	1%	1%	1%	1%	1%	-1%	-4%	-7%	-8%	-7%	-6%	-4%	-2%	-0%	2%	3%	5%	4%	4%	3%	2%	2%
July	1%	1%	1%	1%	1%	1%	0%	-1%	-4%	-8%	-10%	-9%	-6%	-3%	-1%	0%	4%	5%	6%	6%	5%	3%	2%	2%
August	1%	1%	1%	1%	1%	1%	0%	-1%	-4%	-8%	-10%	-9%	-7%	-4%	-2%	-0%	4%	5%	6%	6%	5%	3%	2%	1%
September	1%	1%	1%	1%	1%	1%	1%	-0%	-3%	-6%	-9%	-9%	-7%	-4%	-2%	-0%	3%	5%	6%	6%	5%	3%	2%	1%
October	0%	1%	1%	1%	1%	1%	1%	0%	-2%	-6%	-9%	-9%	-7%	-4%	-2%	-0%	3%	5%	6%	6%	4%	2%	2%	1%
November	0%	0%	0%	0%	0%	0%	0%	-1%	-3%	-6%	-7%	-7%	-5%	-3%	-1%	1%	4%	5%	5%	4%	3%	2%	1%	1%
December	-0%	-0%	0%	0%	0%	0%	0%	-0%	-2%	-5%	-6%	-6%	-5%	-3%	-1%	1%	4%	5%	5%	3%	2%	1%	1%	1%

Residential and nonresidential storage systems are providing grid relief during CAISO peak hours; however, there is significant untapped potential to provide grid benefits (Section 4.3.1). Utility planners are concerned about two peak periods; 1) the gross peak – when overall demand is at its highest and all available electricity supply sources reach their maximum generation and 2) the net peak – when overall demand minus renewable supply sources is reaching peak generation. The total program energy storage capacity in 2023 was over 1,700 MWh. Residential and nonresidential systems discharged roughly 96 MWh (about 6% of total program energy capacity) during the top gross peak hour, and 91 MWh (~5%) during the top net peak hour (which is when the greatest grid stress occurs, and when energy prices are the highest).

We observe differences in storage dispatch between sampled customers participating in ELRP on event days compared to control days (Section 4.3.1). During event days, which in 2023 align with capacity constrained grid hours, systems that were ordinarily arbitraging or self-consuming – but were enrolled in ELRP – were discharging more capacity than they ordinarily would. Peak event discharge reaches roughly 14% of system kWh capacity during the 7pm hour on event days. On non-event days, peak discharge reaches 6% of capacity during the 6pm hour (green bars). Not only were ELRP participants discharging a greater magnitude of system capacity during events but discharge also extended beyond customer load requirements (shaded green area). For ELRP participants, we observe roughly, on average, 37% of kWh

FIGURE 1-7: ELRP VERSUS CONTROL DAY UTILIZATION



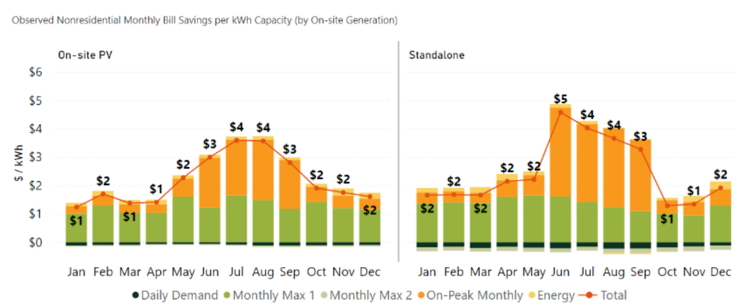
capacity discharged daily. However, on event days, utilization increases to 53% of kWh capacity. During event days, excess discharge was being exported to the grid – a behavior from this cohort of systems that wasn't observed ordinarily throughout the year. We also observe increased charging on and after event days because greater discharge utilization resulted in lower end-of-day state-of-charge (SOC). ***We recommend that the CPUC and SGIP PAs continue to encourage participation in DR programs. Programs like the ELRP that compensate customers for export (rather than just reductions in consumption) should be prioritized as they represent an incremental load reduction relative to typical battery dispatch.***[6]

Customer Bill Impacts

One of the key influences on storage utilization and efficiency is how the system is being managed to provide customer benefits. Most nonresidential systems can realize bill savings on the energy and demand portion of their bill. Residential customers are not subject to demand charges, so bill savings result from energy arbitrage exclusively. Generation customers, whose systems provide a baseload or minimum level of power to meet regular facility demands, generally see higher bill-savings the more energy they produce, even accounting for the added fuel costs. Systems like all-electric fuel cells, and internal combustion (IC) engines that provide more consistent, year-round energy generation see the highest bill savings, up to $145/kW on average during summer months.

SGIP nonresidential storage systems are generally being utilized to reduce non-coincident monthly peak demand and on-peak demand and/or daily demand charges, as well as TOU energy arbitrage (Section 4.2.1). Systems designed for demand charge reductions may incur increases on the energy component of their bill, but demand reduction savings lead to a net decrease in bills overall. Some nonresidential systems perform TOU arbitrage exclusively, and subsequent charging may lead to increased non-coincident peak demand. On average, nonresidential storage dispatch

FIGURE 1-8: NONRESIDENTIAL MONTHLY BILL SAVINGS

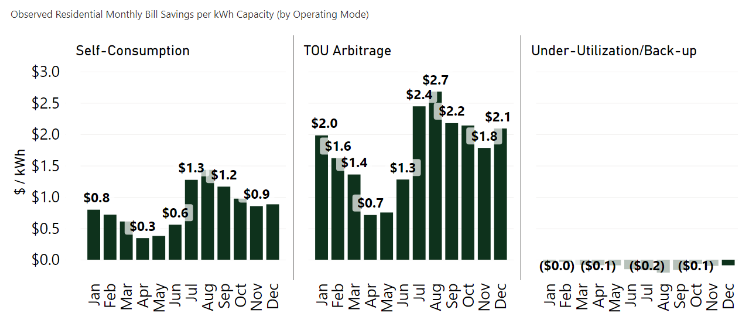


6 All new residential projects are required to exhibit a single cycle round trip efficiency (SCRTE) of 85% or greater, host customers are required to be on an SGIP-approved rate, and customers are also required to be enrolled in an SGIP-approved demand response program by incentive claim submission. ELRP is excluded as an eligible program.

behavior allowed customers to realize overall bill savings for each month of 2023. Overall bill savings are greatest during summer months for both PV paired and standalone systems.

Residential storage systems are being utilized for TOU arbitrage and self-consumption – where the battery is discharged to minimize grid imports during the on-peak period as well as after[7] (Section 4.2.1). Residential systems are producing savings on the energy component of bills, especially during summer months when on-peak and off-peak price differentials are high, and systems are utilized more often. Solar PV paired systems are generating annual savings of roughly $12 per kWh of capacity, and standalone system savings were roughly $2 for each kWh of capacity in 2023. Systems conducting TOU arbitrage are realizing roughly double the average savings than systems conducting self-consumption during summer months. However, under-utilized systems and those likely in backup-only mode are incurring bill increases of roughly $1 for each kWh of capacity.

FIGURE 1-9: RESIDENTIAL MONTHLY BILL SAVINGS



Utility Avoided Costs[8]

When the timing and magnitude of charge and discharge follow the price signal of a customer tariff or a marginal emissions signal, storage performance can lead to customer bill savings and avoided GHG emissions. The same is true for utility costs. Generation technologies provide year-round energy to the customer and to the grid, and these continuous benefits result in significant utility avoided cost benefits.

Gas Turbines provided the most significant avoided cost benefits, averaging $587 per kW of capacity (Section 4.5.2). Across all generation systems, the average avoided cost was $377 per kW of capacity, which was driven by the high energy and generation components. All technologies provided an avoided

7 The transition from Net Energy Metering (NEM) to the Net Billing Tariff (NBT) occurred in April 2023. Given the lag time between SGIP application submittal/approval, installation, interconnection, and incentive payment no sampled projects in 2023 were on the NBT. However, future evaluations will be designed to capture this transition.

8 The 2022 Avoided Cost Calculator was used as the basis for this analysis along with updated cost values to align with actual weather and locational marginal prices (LMP) observed in 2023 (Appendix F).

cost benefit greater than $150 per kW. Non-renewable systems provided the greatest benefits, due to their significant generation contribution throughout the year.

Observed storage behavior was advantageous from an avoided utility cost perspective in 2023 (Section 4.5.1). Overall, SGIP storage systems were charging during lower marginal cost periods and discharging during higher cost periods. Nonresidential and residential systems were discharging during constrained hours. This behavior resulted in a $22.7 million avoided cost benefit across utilities, which represents an increase from each previous impact evaluation – except for 2022.[9] Avoided cost benefits – on average – equaled roughly $17 per kWh of capacity for the residential sector, and $10 per kWh for the nonresidential sector in 2023. While not directly comparable, it's important to note that ratepayer incentives for SGIP storage technologies range from $180 per kWh of capacity to $1,000 per kWh depending on the budget category and time of program participation. While systems are providing utility avoided cost benefits, these benefits – even when calculated over the 10-year permanency period – are far less than the ratepayer incentives issued to participating customers.

FIGURE 1-10: ENERGY STORAGE UTILITY AVOIDED COSTS ($/KWH) BY YEAR AND SECTOR

Storage Optimization

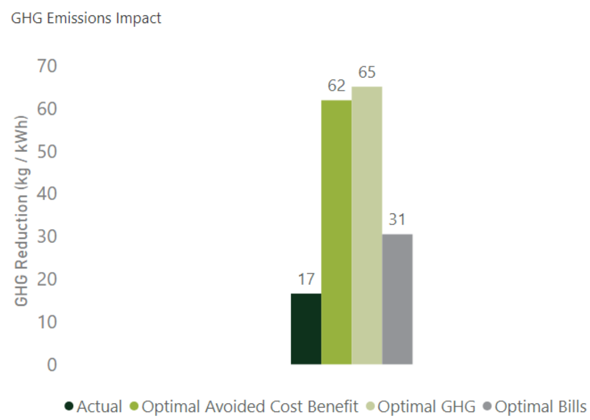
A perfectly designed energy storage system optimized to reduce GHG emissions or respond to grid emergencies would charge only during the lowest marginal emissions or utility cost periods and discharge during higher emissions and price hours (Section 5). Obviously, storage project developers and host customers may not be aware of system-level peak hours, energy prices, or marginal emissions unless they are enrolled in a demand response program or real-time pricing rate where a price signal (or

9 During the first full week in September 2022, protracted high temperatures throughout the state generated critical stress and well-above normal demands on the CAISO and utility systems. This resulted in some very high-cost hours – relative to 2023 – and these hours coincided with hours storage was discharging the greatest magnitudes.

incentive) encourages shifting or reducing demand at specific times. Customers have access to their bill rate structure, but grid-level demand may not be in their purview. On-peak TOU periods provide a broad signal to arbitrage energy over a five-hour period, but emissions vary considerably during this period, narrowing the window for achievement of maximum emissions reductions or utility avoided costs.

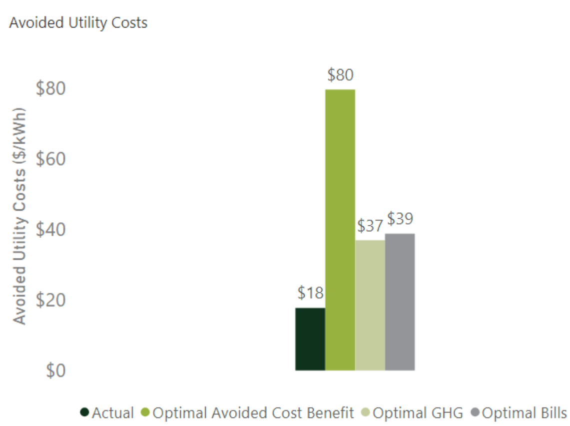
Optimization modeling revealed that the average actual avoided emissions of 17 kg of GHG per kWh of capacity would more than triple if optimized for GHG reductions or utility avoided costs. They would almost double if customer bill savings were optimized (Section 5). Verdant compared observed storage performance to optimal performance following the hourly marginal emissions factor, utility avoided costs, and customer rate schedules. Observed GHG emissions reductions in 2023 and potential reductions achievable following these different signals are all significantly greater than zero. ***We recommend that the CPUC revisit the 5 kg/kWh GHG reduction target and consider replacing it with a more ambitious target that reflects improvements in technology to maximize its potential.***

FIGURE 1-11: RESIDENTIAL GHG OPTIMIZATION



Optimizing residential charge and discharge for utility avoided cost benefits would result in a 4x improvement over actual avoided cost benefits in 2023. Avoided cost benefits would also increase if GHG emissions or bill savings were optimized, but at lower magnitudes (Section 5). Optimization modeling revealed that the average actual avoided cost benefit of $18 per kWh of capacity would increase to $80 if storage followed the avoided cost signal. Most of the incremental avoided cost benefits under this optimization scenario are realized during capacity constrained hours during on-peak summer hours, as well as during morning ramps. ***We recommend the CPUC continue to explore strategies to encourage SGIP participants to enroll in DR or real-time retail rates to encourage increased dispatch during high GHG/demand hours.***

FIGURE 1-12: RESIDENTIAL AVOIDED COST OPTIMIZATION



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2 INTRODUCTION AND OBJECTIVES

California's Self-Generation Incentive Program (SGIP) provides financial incentives for the installation of behind-the-meter (BTM) distributed generation and energy storage technologies that meet all or a portion of a customer's electricity needs. The SGIP is funded by California's ratepayers and managed by Program Administrators (PAs) representing California's major investor-owned utilities (IOUs). These PAs include Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), Southern California Gas Company and the Center for Sustainable Energy (CSE), which implements the program for customers of San Diego Gas and Electric (SDG&E). The California Public Utilities Commission (CPUC) provides oversight and guidance on the SGIP.

2.1 HISTORY OF THE SGIP

Since its inception in 2001, the SGIP has provided incentives to a wide variety of distributed energy technologies including combined heat and power (CHP), fuel cells, solar photovoltaic (PV) and wind turbine systems. While the program was initially designed to help address peak electricity problems in California[10], the program has evolved since 2001, with eligibility requirements, program administration and incentive levels all changing over time. Approval of Assembly Bill (AB) 2778[11] in September 2006 limited SGIP project eligibility to "ultra-clean and low emission distributed generation" technologies. By 2007, growing concerns with potential air quality impacts prompted changes to the SGIP's eligibility rules, and passage of Senate Bill (SB) 412[12] shifted the program's focus from peak-load reduction to greenhouse gas (GHG) reductions.

Beginning in 2009, energy storage systems that met certain technical parameters and were coupled with eligible SGIP technologies – wind turbines and fuel cells – were eligible for incentives.[13] In 2011, standalone storage systems – in addition to those paired with SGIP eligible technologies or PV – were made eligible

10 California Assembly Bill 970, Ducheny. September 6, 2000. http://www.leginfo.ca.gov/pub/99-00/bill/asm/ab_0951-1000/ab_970_bill_20000907_chaptered.html

11 California Assembly Bill 2778, Lieber. September 29, 2006. http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_2751-2800/ab_2778_bill_20060929_chaptered.html

12 California Senate Bill 412, Kehoe. October 11, 2009. http://www.leginfo.ca.gov/pub/09-10/bill/sen/sb_0401-0450/sb_412_bill_20091011_chaptered.pdf

13 CPUC Decision D.08-11-044. November 21, 2008. http://docs.cpuc.ca.gov/PublishedDocs/PUBLISHED/FINAL_DECISION/94272.htm

for incentives.[14] In 2011, the CPUC issued Decision (D.) 11-09-015, which added SGIP eligibility requirements based upon GHG reductions. This was followed by D. 16-06-055 in 2016, which, among other changes, revised how the SGIP is administered.[15] Beginning in 2017, the SGIP was administered on a continuous basis. This change was made largely to curb potential issues with incentives being depleted during program opening, as the program is typically oversubscribed. D. 16-06-055 also supplemented the first-come, first-served reservation system with a lottery. In 2017, D. 17-10-004 established the SGIP Equity Budget, where 25% of SGIP funds collected for energy storage projects were reserved for single family and multi-family low-income housing, including disadvantaged communities.[16]

In August of 2019, the CPUC issued D. 19-08-001 approving GHG emission reduction requirements for the SGIP storage budget.[17] This decision requires SGIP PAs to provide a digitally accessible GHG signal that provides marginal GHG emissions factors (kilograms CO_2/kWh) and directs the SGIP storage impact evaluator to provide summary information on the GHG performance of developer fleets as part of annual SGIP storage evaluations. This decision also defined compliance pathways and operational requirements for residential and nonresidential SGIP energy storage projects based on whether a project was “legacy” or “new”.[18]

On September 12, 2019, the CPUC issued D. 19-09-027 that established an SGIP equity resiliency budget, modified existing equity budget incentives, and approved the transfer of unspent funds to the equity resiliency budget.[19] To help deal with critical needs resulting from wildfire risks in the state, D. 19-09-027 set aside a budget for vulnerable households located in Tier 2 and Tier 3 high fire threat districts, critical services facilities serving those districts, and customers located in those districts that participate in low-income/disadvantaged solar generation programs.

14 CPUC Decision D.10-02-017. February 25, 2010. http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/114312.PDF

15 CPUC Decision D.16-06-055. June 23, 2016. http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=163928075

16 CPUC Decision D. 17-10-004. October 12, 2017. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M197/K215/197215993.PDF

17 CPUC Decision D. 19-08-001. August 9, 2019. http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=310260347

18 “New” projects are those submitting completed applications on or after 4/1/2020. “Legacy” projects are all others completing applications prior to that date.

19 CPUC Decision D. 19-09-027. September 18, 2019. http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=313975481

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In January of 2020, the CPUC issued D. 20-01-021.[20] The decision authorized the collection of ratepayer funds totaling $166 million per year from 2020 to 2024 across the four program administrators. This decision also increased the financial incentive budget for energy storage technologies to 88% of total SGIP funding. Table 2-1 summarizes the timelines and key provisions from each of those decisions.

TABLE 2-1: CPUC DECISIONS INFLUENCING THE SGIP

CPUC Decision	Decision Date	Key Provisions
D. 08-11-044	11/2008	▪ Energy storage systems that met certain technical parameters and were coupled with eligible SGIP technologies (wind turbines and fuel cells) were eligible for incentives
D. 10-02-017	02/2010	▪ Standalone storage systems – in addition to those paired with SGIP eligible technologies or PV – were made eligible for incentives
D. 11-09-015	09/2011	▪ Modified program to include eligible technologies that achieve GHG emission reductions
D. 16-06-055	06/2016	▪ SGIP administered on a continuous basis ▪ Supplemented the first-come, first-served reservation system with a lottery. ▪ Energy storage allocated 75% of program funds ▪ Required minimum biogas blending requirements, up to 100% biogas requirement starting in 2020.
D. 17-10-004	10/2017	▪ 25% of funds collected for energy storage projects are reserved for the SGIP Equity Budget
D. 19-08-001	08/2019	▪ Requires SGIP PAs to provide a digitally accessible GHG signal ▪ Defines compliance pathways and operational requirements for "new" and "legacy" projects and "developer fleets" ▪ Provided GHG enforcement standards for electrochemical and thermal energy storage systems ▪ Directs the SGIP storage impact evaluator to provide summary information on the GHG performance of developer fleets
D. 19-09-027	09/2019	▪ Established the equity resiliency budget ▪ Modified existing equity budget incentives
D. 20-01-021	01/2020	▪ Authorized ratepayer collections of $166 million per year during 2020-2024 to fund the SGIP ▪ 88% of incentive budget reserved for energy storage technologies ▪ Implemented program revisions pursuant to Senate Bill 700 and other program changes
D. 21-06-005	06/2021	▪ Revised program requirements for renewable generation projects

[20] CPUC Decision D. 20-01-021. January 27, 2020. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M325/K979/325979689.PDF

2.2 REPORT PURPOSE

SGIP eligibility requirements and incentive levels have changed over time in alignment with California's evolving energy landscape. Ongoing evaluation reports serve as an important feedback mechanism to assess the SGIP's effectiveness and ability to meet its goals. Decision (D.) 16-06-055 initially stated that an SGIP Measurement and Evaluation (M&E) Plan should be developed by CPUC Energy Division (ED) staff in consultation with Program Administrators. The subsequent passage of SB 700[21] extended annual collections of ratepayer funds for the SGIP through 2024 and extended administration of the program through 2025. SB 700 also required the CPUC to adopt new program rules regarding GHG emissions impacts and restricted all SGIP generation technologies to 100% renewable fuel by 2020. Furthermore, Ordering Paragraph (OP) 7(h) of D.19-09-027 required the SGIP program administrators to develop an M&E Plan for 2021-2025, which was ultimately approved in May of 2022, and finalized in January of 2023.

2.3 GOALS AND OBJECTIVES

The primary objective of this study is to satisfy the requirements of the 2021-2025 M&E Plan by evaluating the performance of incentivized SGIP systems operating during calendar year 2023. Verdant analyzed several different observed performance metrics and impacts and compared them to expectations and program requirements. The research questions shown below are informed by the M&E Plan, along with results garnered from past impact evaluations.

21 California Senate Bill 700, Wiener. September 27, 2018. https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180SB700

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TABLE 2-2: OVERVIEW OF RESEARCH OBJECTIVES AND METHODS

Quantitative Research Objectives	Methods
Observed Performance Metrics	
• Are projects maintaining minimum capacity factors, RTEs and cycling requirements? • How have project efficiencies and utilization changed over the years? • How do utilization and system efficiencies (electrical, thermal, and total) differ based on different segmentation – facility type, operating mode, TOU period, season, presence of on-site generation, capacity constrained hours, fuel type? • To what extent do SGIP technologies employ renewable fuel and how does their performance compare to non-renewable and blended projects? • Quantification of electricity generated, fuel consumed (both renewable and non-renewable), and useful heat recovered? • Non-coincident peak demand impacts?	Analysis of metered data for energy storage system charge and discharge, generation system output, and facility load at the utility meter. Optimal dispatch modeling.
Grid Impacts and Utility Marginal Costs	
• How do systems currently operate throughout grid constrained hours (CAISO net peak and gross peak hours) and utility coincident peak? What are the key differences between groups based on different segmentation? • How are resources that charge from renewable generation exporting to the grid? How often? At what times? At what capacities? • How do systems affect utility and grid costs? • Are storage systems exporting and, if so, is export energy renewable based? • Quantification of impacts from systems participating in wholesale markets and demand response?	Comparing CAISO and IOU load data to the metered storage and generation data throughout specific hours throughout the year. Quantification of dispatch behavior throughout demand response and wholesale market participation. Quantification of grid benefits using the Avoided Cost Calculator (ACC) and locational marginal energy prices, Optimal dispatch modeling.
Environmental Impacts	
• Are projects reducing GHG emissions? Have emissions changed over time? • Do emissions vary by key segmentation – facility type, developer/manufacturer, presence of on-site solar, rate schedule, legacy status, etc? • What are developer fleet emissions? • How does optimal GHG emissions reductions compare to observed emissions and how can changes to operation lead to increased GHG emissions reductions? • Quantification of emissions impacts based on the various emissions components – generation technology by fuel type, electric power plant, heating and cooling, biogas treatment?	Analysis of emissions avoided during storage discharge and emissions increases during storage charging. Comparison of emissions impacts by component for differing technologies, fuels, and baseline types; impact of electric power plant, heating and cooling loads, and biogas treatment. Optimal dispatch modeling.
Integration of On-site Solar PV	
• How does storage interact with systems paired with PV? Does behavior differ for standalone systems and by different segmentation? Do discharge patterns differ by TOU periods? • What is the relationship between storage sizing and PV sizing? How does that relationship correlate to customer, grid, and environmental impacts?	Analyze and quantify storage performance throughout PV generating hours - percentage of energy charged, magnitude of charge relative to size of PV generator (kW, kWh)
Customer Resiliency	
• How does storage behave during outages? • Quantification of BTM consumption during PSPS events compared to similar non-PSPS days? Changes in utilization, consumption, PV generation? • How are critical needs facilities being utilized to provide community support during utility outages?	Analysis of storage, load, and PV data during PSPS and other outage events compared to like days. Review of outage data provided by utilities. Review of program tracking.
Customer Bill Impacts	
• Are SGIP participants realizing bill savings from storage and generation utilization? • Are nonresidential customers realizing demand charge savings? TOU energy savings? • How do customer bill impacts differ by rate schedule, month? • How does optimal bill savings compare to observed customer bill savings? • Co-optimization with GHG reductions or utility avoided costs?	Analysis of changes to a customer's bill from a baseline where no storage exists using Verdant's Bill Calculator and Cost-Effectiveness Tool. Optimal dispatch modeling.
Storage Costs	
• Quantification of self-reported storage costs? What comprises storage eligible costs - capital expenditure, labor, interconnection, permitting? • How have these costs changed over time? Do costs differ by component or by developer/manufacturer?	Analysis of disaggregated eligible costs from program tracking data. Analysis of trends based on developer/manufacturer, size of system, program year of application.
Population Impacts	
• Quantification of storage and generation impacts to the population of the SGIP?	Ratio estimation. Extrapolation of sample-level impacts to the population of projects.

2.4 METHODOLOGY OVERVIEW AND SOURCES OF DATA

The empirically observed impacts reported in this evaluation are based directly on metered performance data collected from a sample of SGIP projects. The evaluation team used sampling methods and estimated population-level impacts using statistical approaches that conform to industry standards for impact evaluations (Section 5). Sources of data used in this evaluation include:

- The SGIP Statewide Project Database – contains project characterization information such as incentivized capacity, host customer address, electric utility, project developer and upfront payment date
- Installation Verification Inspection Reports – used to supplement the Statewide Project Database with additional details such as inverter size (kW), battery size (kWh) and storage system type
- Metered generation, charge, and discharge data
  - Data for systems subject to PBI data collection rules were downloaded from the Statewide Project Database
  - Data for a sample of all energy storage systems (regardless of size) were requested and received from project developers
  - Data for generation systems came from both customers and performance data providers
- Metered customer interval load and tariff information (energy storage) were requested and received from the electric IOUs and project developers, where available
- Marginal emissions data were collected from the GHG signal provider, WattTime[22]
- Utility avoided cost information was developed using locational marginal price and GHG Allowance price data from CAISO, as well as marginal cost data from the CPUC 2023 Avoided Cost Calculator (ACC)
- Additional information such as electric outage information, paired generator (PV, fuel cell, etc.) characteristics and participation in demand response (DR) programs, where applicable, were received from project developers and electric utilities

The data were reviewed to ensure data integrity and quality. Characterization of the sample including performance metrics and program impact estimates by various categorical variables are included in Section 4. Details on the data integrity and quality control (QC) methods are provided in Appendix B.

[22] https://sgipsignal.com/

2.5 REPORT ORGANIZATION

This report is organized into five sections and five appendices as described below.

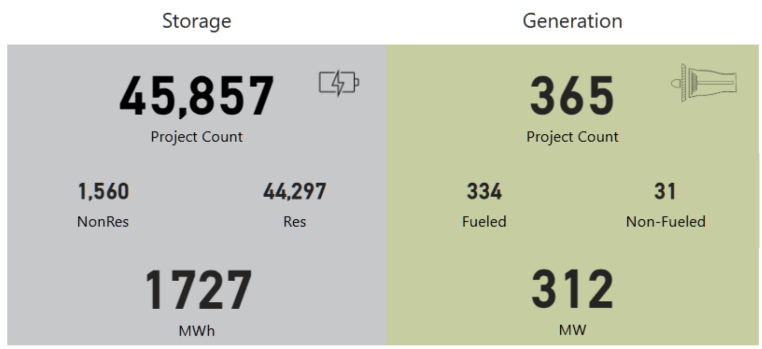
- Section 1 provides an executive summary of the key findings and recommendations from this evaluation
- Section 2 summarizes the purpose, scope, methodology and organization of the report
- Section 3 provides a detailed description of the SGIP population
- Section 4 presents performance metrics and observed impacts for sampled projects, as well as estimated total impacts for the overall population
- Section 5 presents observed energy storage performance to optimal dispatch
- Appendix A describes how customer bill impacts were estimated
- Appendix B presents the sources of data used in this evaluation and the quality control procedures used to verify storage data
- Appendix C characterizes the metered sample
- Appendix D provides methodologies related to greenhouse gas calculations
- Appendix E provides methodologies related to utility avoided costs

3 STUDIED POPULATION

The 2023 SGIP energy storage and generation population is collected from the most recent version of the statewide project database and downloaded at www.selfgenca.com. This dataset provides the current listing of all projects that have applied to the program and contains important information, including incentive status, project developer name, system size, system location, electric utility name, and whether a project is paired with a renewable generator (among other fields).

The energy storage population subject to evaluation is defined as all projects; 1) receiving an upfront SGIP incentive on or before December 31, 2023, *and* 2) having status of "Payment Completed" or "Payment PBI in Process" *and* 3) where equipment type is electrochemical, mechanical, or thermal storage.

FIGURE 3-1: SGIP 2023 EVALUATION POPULATION

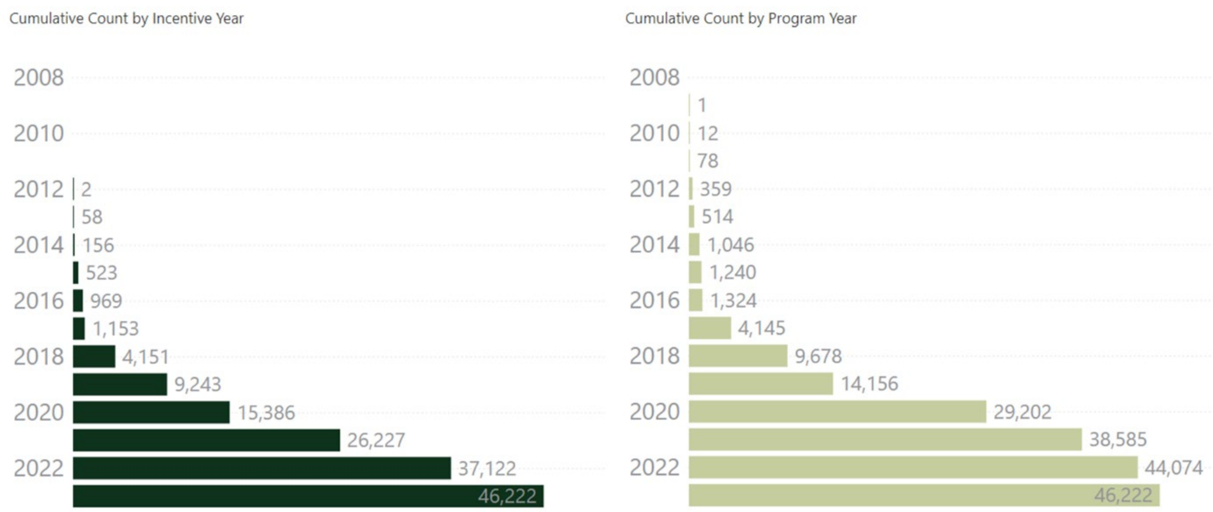


The generation population subject to evaluation is defined as all projects; 1) receiving an upfront SGIP incentive on or before December 31, 2023, *and* 2) having status of "Payment Completed" or "Payment PBI in Process" *and* 3) where equipment type is gas turbine, fuel cell, microturbine, wind turbine, waste heat to power, pressure reduction turbine, or internal combustion engine *and* 4) still within their permanency period as specified by the Program Handbook.

During 2023 there were almost 46,000 storage projects in the population, with over 44,000 of them being residential systems. On the other hand, only 365 generation systems were within the SGIP population, still being within their permanency period, 334 of them were fueled systems, running on either natural gas, renewable fuel, or a blend of both. The program has incentivized over 1,700 MWh of storage capacity, and 312 MW of capacity of generation projects.

Figure 3-2 presents the growth in SGIP population over time by program year (PY) and upfront payment (or incentive) year for projects within their permanency period. The program year represents the year a project applied to the SGIP, and the incentive year corresponds to when the participating customer ultimately received their incentive payment. Given potential lag times between program application and system installation, interconnection and administrative requirements, projects may receive their incentive (or upfront payment) a year or two after initially applying to the program. This is evident in the figure below, where the total number of projects applying within a given year is greater than the number of projects subject to evaluation for that year. Since the program application process can extend beyond one calendar year, our team defines the population of SGIP systems subject to evaluation for a given year based on when the customer received their upfront payment, rather than when they initially applied to the program.[23]

FIGURE 3-2: SGIP CUMULATIVE PROJECT COUNT GROWTH OVER TIME



3.1 COMPOSITION OF SGIP ENERGY STORAGE POPULATION

The first step in the evaluation design process was to define the energy storage population subject to evaluation for this 2023 study. Host customers and project applicants are at different stages of the application process at any given time, so initial cut points were created to frame the population and were based on three categories collected from the statewide project database. These categories include 1) all projects that received an upfront SGIP incentive on or before December 31, 2023, *and* 2) have fully qualified state of "Payment Completed" or "Payment PBI in Process" *and* 3) where equipment type is electrochemical, mechanical, or thermal storage. While this impact evaluation covers storage performance in 2023, the population considers cumulative growth, in that every project receiving an incentive from program inception through the end of 2023 is subject to evaluation.

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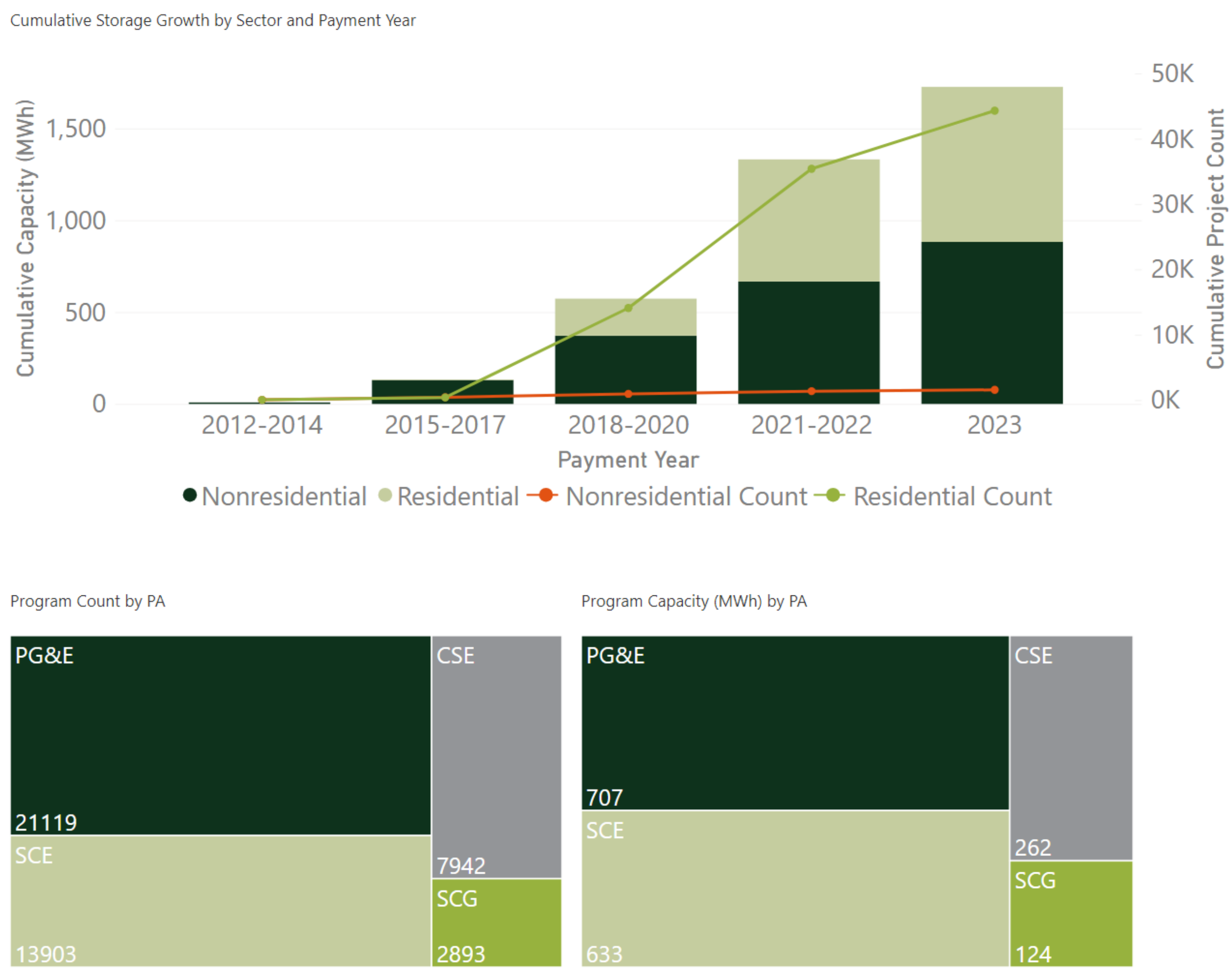
[23] For example, a participant may apply to the SGIP in 2022, but not receive their incentive payment until 2024. This customer would NOT be part of the population frame for 2023.

Storage Composition by Customer Sector

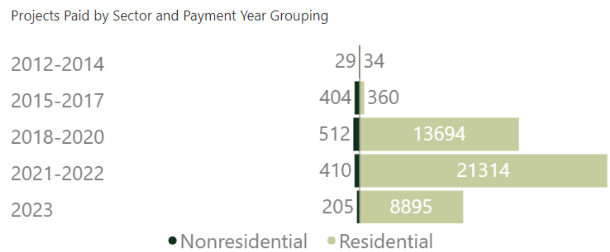
Figure 3-3 presents the cumulative growth of SGIP incentivized energy storage from 2012 – when the first nonresidential systems received incentives – to the end of 2023. By the end of 2023, the SGIP provided incentives for **44,297 residential** and **1,560 nonresidential** projects representing roughly **845 MWh and 882 of incentivized capacity** for each sector, respectively. As of December 31, 2023, all but eight were electrochemical (battery) energy storage technologies.[24]

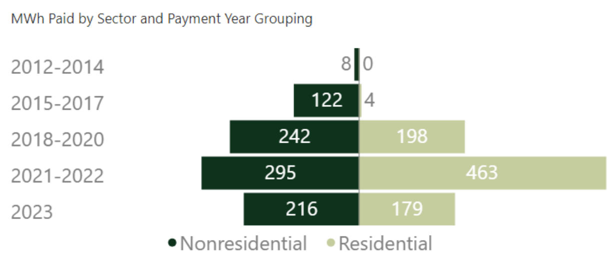
FIGURE 3-3: SGIP STORAGE CUMULATIVE GROWTH BY CUSTOMER SECTOR AND INCENTIVE PAYMENT YEAR



[24] Eight thermal energy storage technologies have received incentives. Two small residential applications, and six nonresidential installations.

Standalone nonresidential energy storage was the predominant technology in earlier years, but new program funding and budget categories with differing incentive levels allowed newer, more sophisticated energy storage configurations access into the program. In 2016, 75% of the SGIP budget was allocated to energy storage and the program began experiencing a significant increase in participation. The overall share of the SGIP budget reserved for storage technologies then increased from 75% to 88% in 2020. These program changes ultimately explain the significant growth in residential program participation, with over 44,000 systems receiving incentives by the end of 2023. New project applications in the nonresidential sector have slowed, except for in the Equity Resiliency Budget (ERB) category. While over 97% of the SGIP storage population are residential projects, the program capacity is roughly split between the residential and nonresidential sectors. PG&E and SCE constitute the greater share of projects and capacity, followed by CSE and SCG.





The program has continued to pay out incentives since the most recent impact evaluation was completed for calendar year (CY) 2021-2022. This growth is represented by the roughly 9,000 residential and nonresidential projects receiving SGIP incentives between January 1, 2023 and December 31, 2023, and the 405 MWh of capacity added (inset figure). This coincides with several changes made to the SGIP budget allocation process and program eligibility requirements in 2020. In previous program years, the Small Residential Storage budget category, which was open to any residential IOU electric or gas customer, represented over 90% of all SGIP applications. Starting in 2020, the program shifted focus towards equity projects and customer resiliency, which is primarily captured in the Equity Resiliency Budget category.

Storage Composition by Budget Category

The SGIP energy storage budget is broken out into seven categories: Large-Scale, Small Residential, Residential Equity, Equity Resiliency, Nonresidential Equity, San Joaquin Valley Pilot (SJV Pilot) and Heat Pump Water Heaters. The SGIP energy storage budget is 88% of the overall 2020-2024 budget, and the remaining 12% of the budget is reserved for renewable generation technologies. Most of the energy storage budget (63% of the overall 2020-2024 budget) is allocated to the Equity Resiliency budget category with the remaining 25% of the energy storage budget split between the remaining categories. Table 3-1 presents the overall distribution of budget allocation along with a brief description of the budget categories.

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TABLE 3-1: DESCRIPTION OF SGIP PY 2020-2024 BUDGET CATEGORIES[25]

Budget Category	Budget Allocation	Brief Budget Category Description
Equity Resiliency (Residential and Nonresidential)	63%	▪ Intended for vulnerable households located in Tier 2 and Tier 3 High Fire Threat Districts (HFTDs) or customers who have been subjected to two or more Public Safety Power Shutoff (PSPS) events.
Renewable Generation	12%	▪ Open to generation technologies. All new generation projects must be 100% fueled with renewable fuel.
Large-Scale Storage	10%	▪ Open to **nonresidential projects or residential projects greater than 10 kW.**
Small Residential Storage	7%	▪ Open to **residential projects less than or equal to 10 kW.**
Residential Equity	3%	▪ Open to single-family low-income housing or multi-family low-income housing, regardless of project size.
Nonresidential Equity	n/a	▪ No additional collections authorized. Received funding until exhaustion of previous budget carryover.
San Joaquin Valley Pilot	n/a	▪ No additional collections authorized. Received funding from SCE and PG&E's unused nonresidential equity budget.

Current budget category designations were not created until PY 2017, so projects applying to the program before then were subject to different eligibility and compliance requirements. Furthermore, the incentive structure changed in PY 2017 from a power output (kW) basis to an energy storage (kWh) basis. Verdant has considered many of the programmatic changes which have shaped the program over the years as we reviewed the statewide program database and designed this study.

Below we highlight the program participant count and system capacity contributions for each budget category throughout the years – Figure 3-4 presents growth in project count and Figure 3-5 presents growth in MWh capacity. Payment years have been combined for ease of presentation, but they generally align with significant changes to incentive and program structure over time. Projects identified as "2017 Prior" represent those receiving incentives prior to the creation of the current budget categories (systems applying to the program prior to 2017). Budget categories like Small Residential and Equity Resiliency (ERB), which was created in PY 2020, account for a significant increase in total projects beginning in 2021-

[25] D.20-01-021 included a 5% budget allocation for heat pump water heaters (HPWH). The budget for HPWH incentives has since increased. However, the HPWH element of the SGIP is largely independent of the energy storage and generation elements from an administration and evaluation standpoint. As such, changes to the HPWH program are not documented in this report.

2022. Currently, incentives received through the Small Residential budget category represent the largest share of projects, followed by ERB. Measured in program capacity, the Large-Scale Storage category represents the greatest share because this category is open to both residential and nonresidential systems – the latter of which are generally much larger in size. The Equity categories have experienced the lowest participation in the program. By the end of 2023, Small Residential, ERB and Large-Scale Storage represented 97% of all energy storage incentives received within the SGIP since program inception.

FIGURE 3-4: SGIP STORAGE PROJECT COUNT GROWTH BY BUDGET CATEGORY AND PAYMENT YEAR

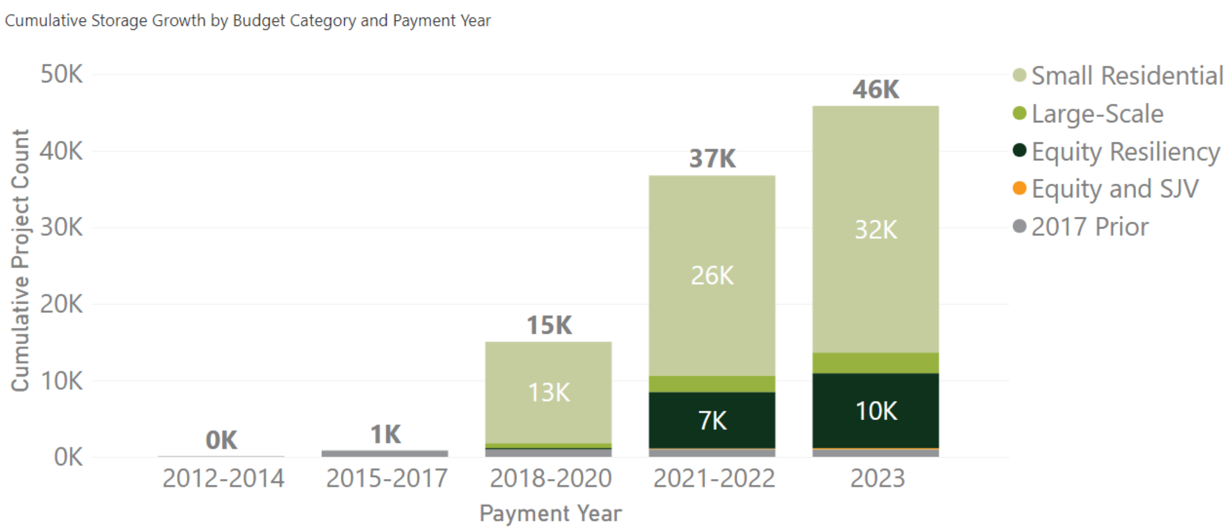
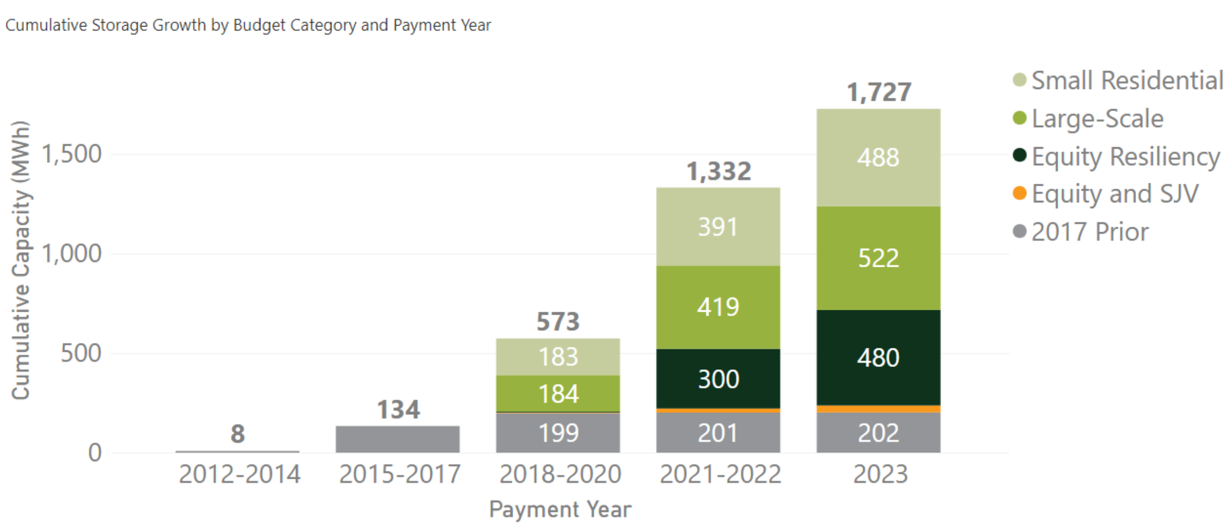


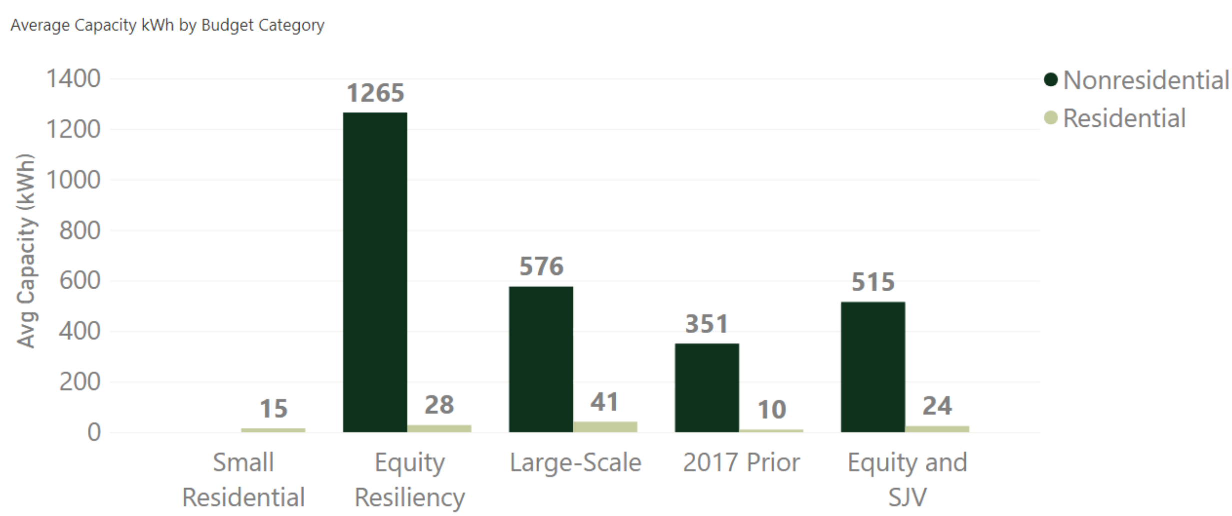
FIGURE 3-5: SGIP STORAGE CAPACITY GROWTH (MWH) BY BUDGET CATEGORY AND PAYMENT YEAR



Nonresidential systems are almost always larger and therefore represent a greater contribution to total program impacts. They range in size from roughly 10 kWh to over 5,000 kWh, with an average capacity of almost 600 kWh. Residential systems generally range from 10 kWh to 40 kWh, with an average capacity of 19 kWh.

We also observe significant variation in installed capacities across budget categories for a given sector. Nonresidential installations in the ERB are, on average, two times larger than nonresidential installations in other budget categories. The ERB installations are installed at critical services facilities, which in the event of an outage, could require larger and longer duration batteries to provide community resiliency. The same is true in the residential sector. Storage systems installed in ERB are, on average, twice the size of Small Residential systems (28 kWh compared to 15 kWh). Customers experiencing PSPS outages and needing to service critical loads like medical devices may require a larger system to provide lifesaving support throughout a multi-day outage. Furthermore, residential customers receiving incentives in Large-Scale Storage might have much greater underlying load requirements than customers in the Small Residential category – which may explain why systems installed in that category are, on average, three times larger than those in the Small Residential budget category.

FIGURE 3-6: AVERAGE INCENTIVIZED CAPACITY (KWH) BY BUDGET CATEGORY AND CUSTOMER SECTOR



Participation within specific budget categories is also influenced by budget allocation (as discussed previously) and upfront incentive levels. The ERB and Equity budget incentives can reach up to $1.00 and $0.85 per watt hour, respectively, while Large-Scale and Small Residential incentives are allocated through a stepdown process – where initial incentives were provided at $0.50 per watt hour, and the incentive is reduced (to as low as $0.15 per watt hour) as stepped participation targets are met and closed, and new steps open.

Figure 3-7 and Figure 3-8 presents how residential and nonresidential incentive levels differ by budget category. The reference line for median incentive is also provided and the size of points is proportional to the total count of projects that have received incentives within a budget category. While the nonresidential ERB incentive is also $1.00 per watt hour, this figure presents upfront incentive payments. Nonresidential systems are subject to Performance-Based Incentive (PBI) requirements where 50% of the incentive is paid upfront and the remaining 50% is paid out over the next five years and based on project performance. All these projects have received their upfront incentive between 2021-2023, so they haven't received their full incentive.

FIGURE 3-7: RESIDENTIAL UPFRONT INCENTIVE BY PAYMENT YEAR AND BUDGET CATEGORY

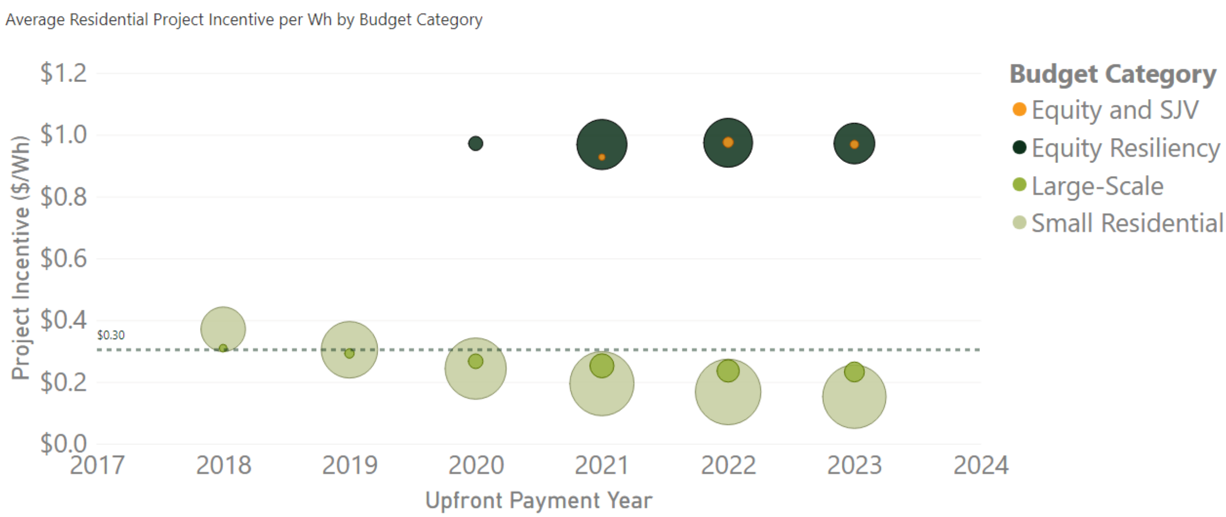


FIGURE 3-8: NONRESIDENTIAL UPFRONT INCENTIVE BY PAYMENT YEAR AND BUDGET CATEGORY

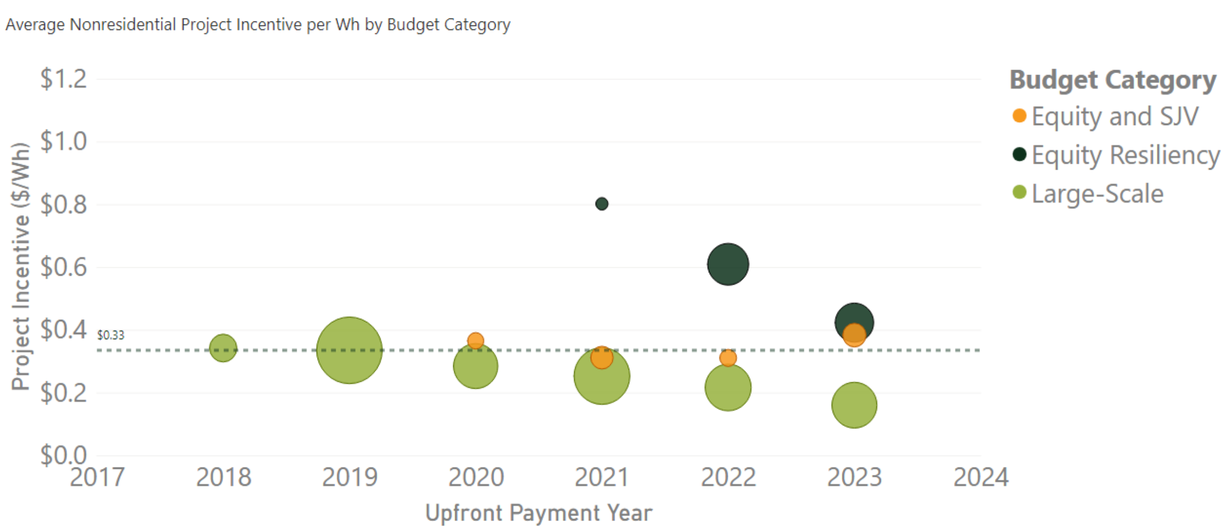


Figure 3-9 and Figure 3-10 convey how, over time, those self-reported eligible costs vary based on customer sector and budget category. Unlike incentive levels, which have either remained constant in categories like the ERB, SJV, and Equity budgets, or have declined like in the Small Residential and Large-Scale Storage categories, total eligible costs have all increased over time. The increase has been independent of the budget category – at least within the residential sector. For example, the average self-reported total eligible cost in the Small Residential category increased from $0.88 per watt hour in 2018 to $1.27 per watt hour in 2023.

FIGURE 3-9: RESIDENTIAL ELIGIBLE COSTS BY PAYMENT YEAR AND BUDGET CATEGORY

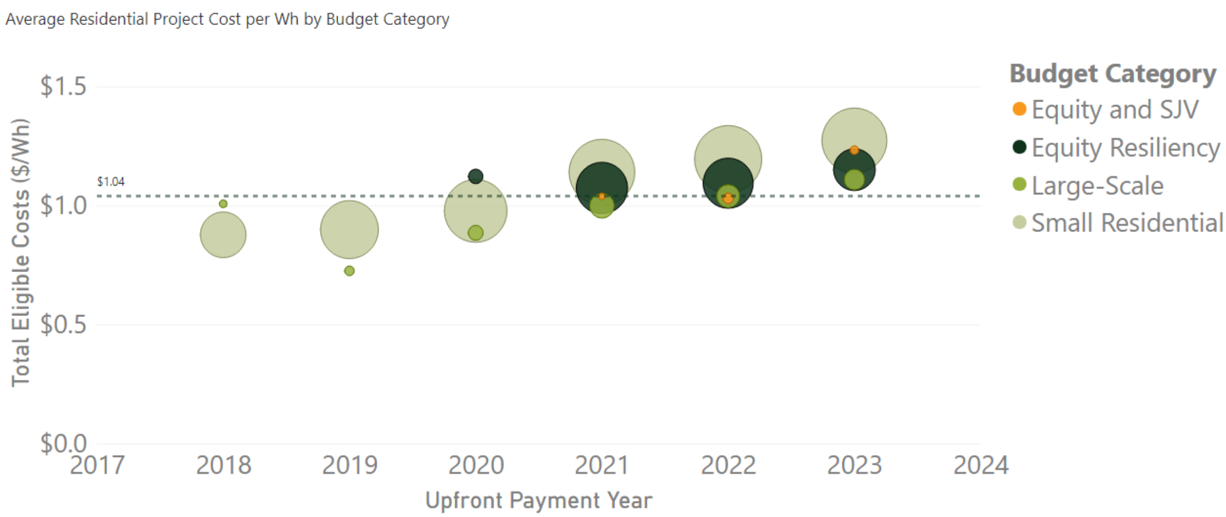
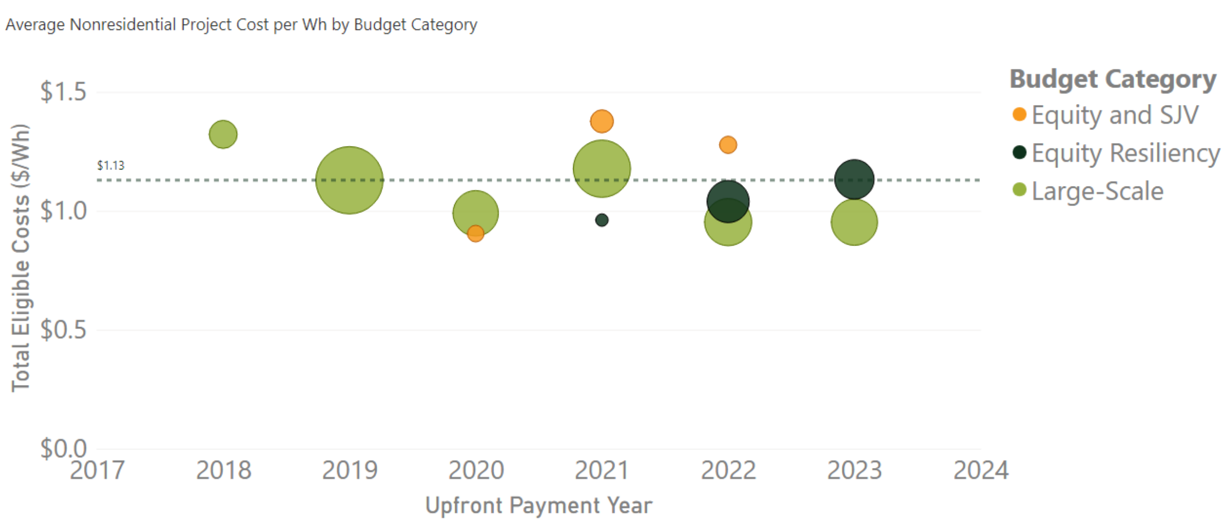


FIGURE 3-10: NONRESIDENTIAL ELIGIBLE COSTS BY PAYMENT YEAR AND BUDGET CATEGORY



Steady cost increases and static or declining per-Wh incentives over time have increased the share of costs borne by participating customers. General market participation has been largely unaffected by these increased out-of-pocket expenses, and the ERB has afforded participating customers with a large enough incentive to cover all or most of the system and installation costs. As part of our research, Verdant will continue to track changes in program composition and storage costs to better gauge how a market as dynamic as behind-the-meter energy storage influences SGIP participation in the various budget categories (and vice versa).

Figure 3-11 presents the relationship between total eligible costs and residential customer incentives by budget category. Average customer incentives (in total $) are represented on the vertical axis and self-reported eligible costs (in total $) are on the horizontal axis. The graph is split by dark gray shading in the upper left and lighter gray shading in the lower right. Anywhere on that line separating the two areas would suggest that the total incentive covered the entire cost of the system. If below that line and within the light gray area, costs exceed the incentive. Equity and ERB incentives cover almost the entire eligible costs of the systems, whereas costs exceed the incentive in the Small Residential and Large-Scale Budget categories. The median incentive across budget category – roughly $17,000 – is also provided as the horizontal dark dashed line. The median total eligible costs – roughly $28,000 – are provided as the vertical red dashed line. Results for the nonresidential sector follow in Figure 3-12.

FIGURE 3-11: RESIDENTIAL ELIGIBLE COSTS VERSUS INCENTIVES BY BUDGET CATEGORY

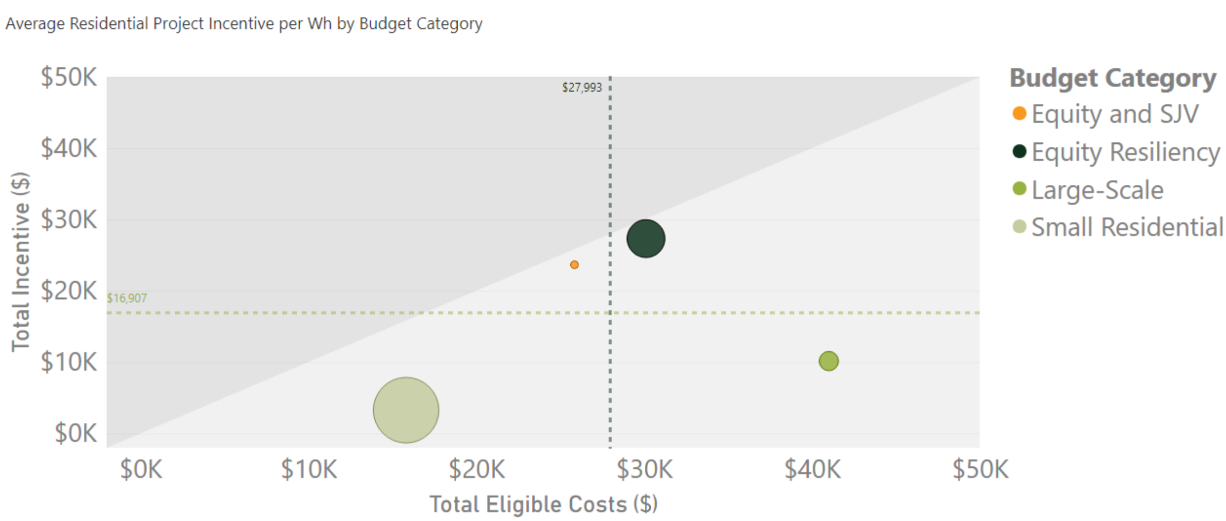


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FIGURE 3-12: NONRESIDENTIAL ELIGIBLE COSTS VERSUS INCENTIVES BY BUDGET CATEGORY

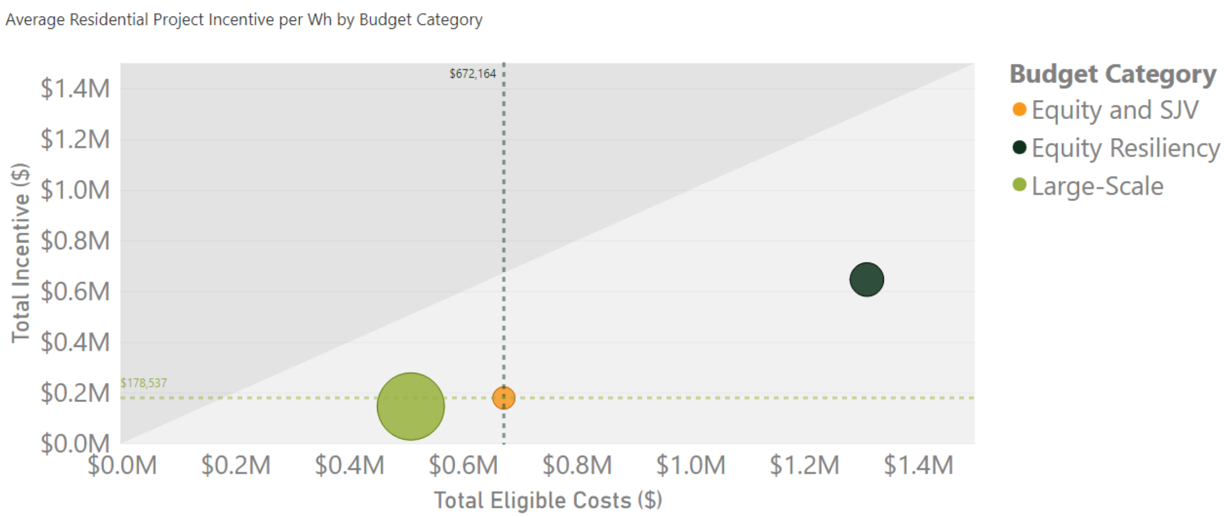

Table 3-2 summarizes the above information and includes, for each budget category and payment year grouping (the years in which the incentive was actually paid out); 1) total project counts, 2) average system sizes (kW and kWh), and 3) average eligible costs, incentives, and out-of-pocket expenses per watt hour of capacity.[26] For ERB participants in 2023, the SGIP incentive covered all but $4,000 ($0.18 per watt hour of capacity) of the roughly $31,000 average total eligible costs. In 2017-2018, the incentive covered roughly 50% of the total eligible costs for Small Residential participants. In 2021-2022 the incentive covered roughly 15% of the total eligible costs. By 2023, with increased eligible costs and reduced incentive levels, participants were responsible for roughly $17,000, or 90%, of the $19,000 project installation ($1.12 per watt hour of capacity).

Summaries from the nonresidential sector are also presented in Table 3-3. Again, incentive estimates represent upfront payment amounts, and nonresidential customers are subject to PBI requirements where 50% of the incentive is paid upfront. Most of these customers have or will recover the subsequent 50% of the incentive over five years from the time of the upfront payment (depending on performance and compliance).

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[26] Out-of-pocket expenses don't consider any credits claimed through the Federal Investment Tax Credit (ITC).

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TABLE 3-2: AVERAGE RESIDENTIAL INCENTIVES AND COSTS BY BUDGET CATEGORY AND PAYMENT YEAR

N Prj, Eligible Cost/Wh, Incentive/Wh, Out-of-Pocket/Wh, kWh, kW
BY BUDGET CATEGORY, PAYMENT YEAR

Budget Category	Payment Year	N Prj	kW	kWh	Eligible Cost/Wh	Incentive/Wh	Out-of-Pocket/Wh
Equity and SJV	2021-2022	70	9	25	$1.03	$0.96	$0.07
Equity and SJV	2023	29	9	24	$1.23	$0.96	$0.28
Equity Resiliency	2019-2020	169	9	24	$1.12	$1.02	$0.10
Equity Resiliency	2021-2022	7139	11	28	$1.08	$0.97	$0.11
Equity Resiliency	2023	2319	11	28	$1.15	$0.97	$0.18
Large-Scale	2017-2018	18	14	35	$1.01	$0.31	$0.70
Large-Scale	2019-2020	228	17	44	$0.85	$0.27	$0.58
Large-Scale	2021-2022	1245	16	42	$1.02	$0.25	$0.77
Large-Scale	2023	425	15	39	$1.11	$0.24	$0.87
Small Residential	2017-2018	2831	6	13	$0.88	$0.38	$0.50
Small Residential	2019-2020	10433	6	14	$0.94	$0.27	$0.67
Small Residential	2021-2022	12858	6	16	$1.17	$0.18	$0.99
Small Residential	2023	6122	6	16	$1.27	$0.15	$1.12
Overall		**43886**	**8**	**19**	**$1.09**	**$0.39**	**$0.70**

TABLE 3-3: AVERAGE NONRESIDENTIAL INCENTIVES AND COSTS BY BUDGET CATEGORY AND PAYMENT YEAR

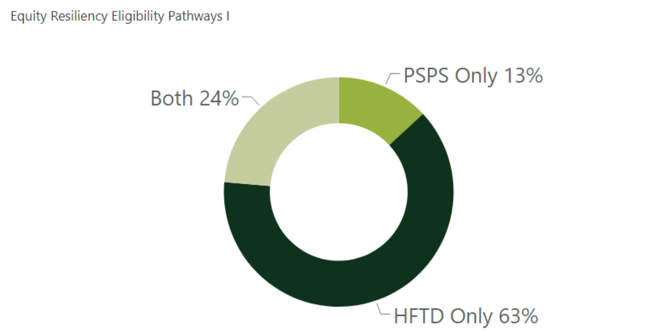
N Prj, Eligible Cost/Wh, Incentive/Wh, Out-of-Pocket/Wh, kWh, kW
BY BUDGET CATEGORY, PAYMENT YEAR

Budget Category	Payment Year	N Prj	kW	kWh	Eligible Cost/Wh	Incentive/Wh	Out-of-Pocket/Wh
Equity and SJV	2019-2020	9	130	371	$0.90	$0.40	$0.51
Equity and SJV	2021-2022	31	237	501	$1.34	$0.41	$0.93
Equity and SJV	2023	23	208	590	$3.16	$0.41	$2.75
Equity Resiliency	2021-2022	91	213	1040	$1.04	$0.63	$0.41
Equity Resiliency	2023	75	308	1538	$1.13	$0.45	$0.68
Large-Scale	2017-2018	34	150	292	$1.32	$0.34	$0.98
Large-Scale	2019-2020	345	224	475	$1.09	$0.32	$0.77
Large-Scale	2021-2022	283	303	644	$1.09	$0.25	$0.83
Large-Scale	2023	107	357	811	$0.95	$0.17	$0.78
Overall		**998**	**263**	**687**	**$1.13**	**$0.33**	**$0.80**

Storage Composition by Eligibility Criteria

Budget categories have different criteria which guide the types of installations eligible for a given incentive. Some are exclusively predicated on the size of the system like in the Small Residential or Large-Scale Storage budgets, and some have strict income qualification minimums or a requirement to be installed in a disadvantaged community like in the Equity budget. The ERB is unique in that it has two eligibility criteria. The first mandatory criteria is that the system must be installed within a Tier 2 or Tier 3 HFTD, or the host customer must have recently experienced at least two PSPS events. As of the end of 2023, most installations – 87% of ERB participants – were in HFTDs, with 13% qualifying for this eligibility requirement based on PSPS history.

FIGURE 3-13: EQUITY RESILIENCY ELIGIBILITY PATHWAYS 1



The second eligibility criterion considers other demographic, property, and participant information. Evident in the inset figure, most participants secured eligibility through having a medical baseline (69%) or an electric well pump installed at the property (26%). Very few low-income participants (2% of all ERB installations) garnered incentives within the ERB category or used that eligibility pathway. The remaining 2% either provided critical services or the installation occurred in conjunction with a low-income solar program like SASH.

FIGURE 3-14: EQUITY RESILIENCY ELIGIBILITY PATHWAYS 2

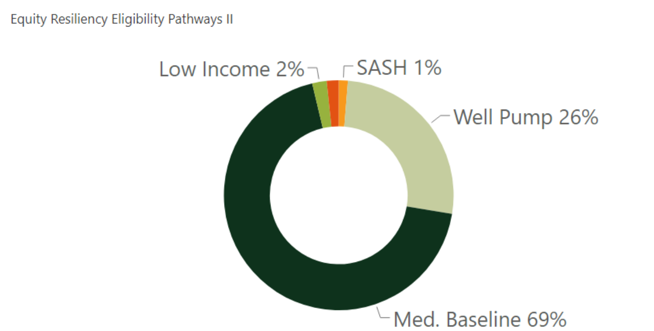
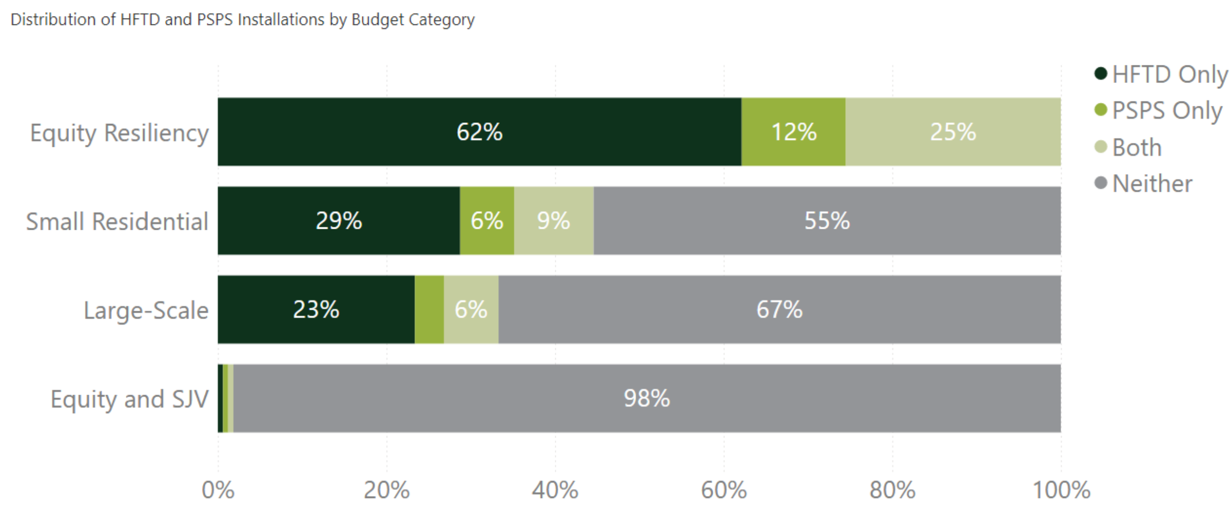


Figure 3-15 also presents the first eligibility criterion for ERB participants along with where and if participants from other budget categories installed systems in HFTDs and/or experienced PSPS events. These other budget categories don't have the same eligibility requirements (or the up to $1.00 per watt hour incentive), so they were likely installing energy storage for personal resiliency without qualifying for the ERB incentive or they participated in the program prior to the creation of the ERB. Almost half (45%) of Small Residential and nearly 33% of Large-Scale Storage installations have occurred in HFTDs, PSPS areas, or both.

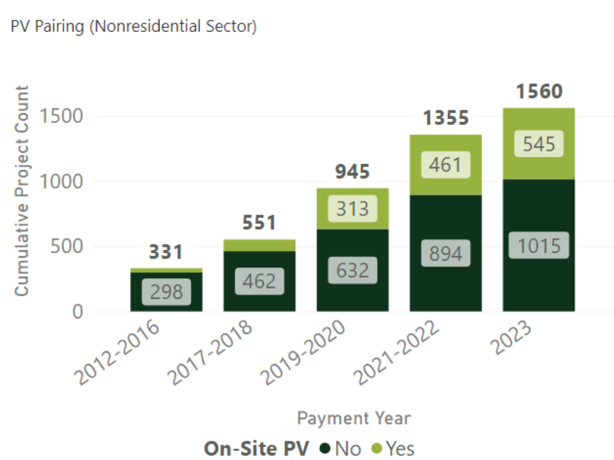
FIGURE 3-15: DISTRIBUTION OF HFTD AND PSPS INSTALLATIONS BY BUDGET CATEGORY

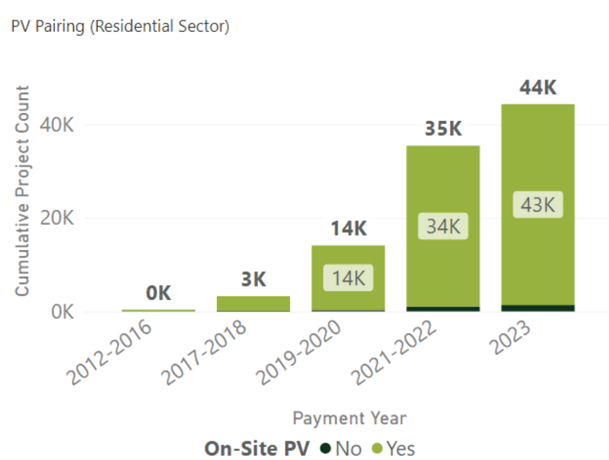


Storage Composition by On-Site Solar Generation

While D. 10-02-017 made standalone storage systems – in addition to those paired with SGIP eligible technologies or PV – eligible for incentives, solar PV attachment rates within the SGIP didn't really tick up in the nonresidential sector until 2019 when a large fleet of solar plus storage paired systems began receiving incentives. Early residential storage installations were standalone, but when the program began allocating sufficient resources and funding to residential customers in 2017, the program saw a significant increase in solar plus storage installations, along with storage installations retrofit onto existing solar PV.

FIGURE 3-16: STORAGE COMPOSITION BY PRESENCE OF ON-SITE SOLAR GENERATION

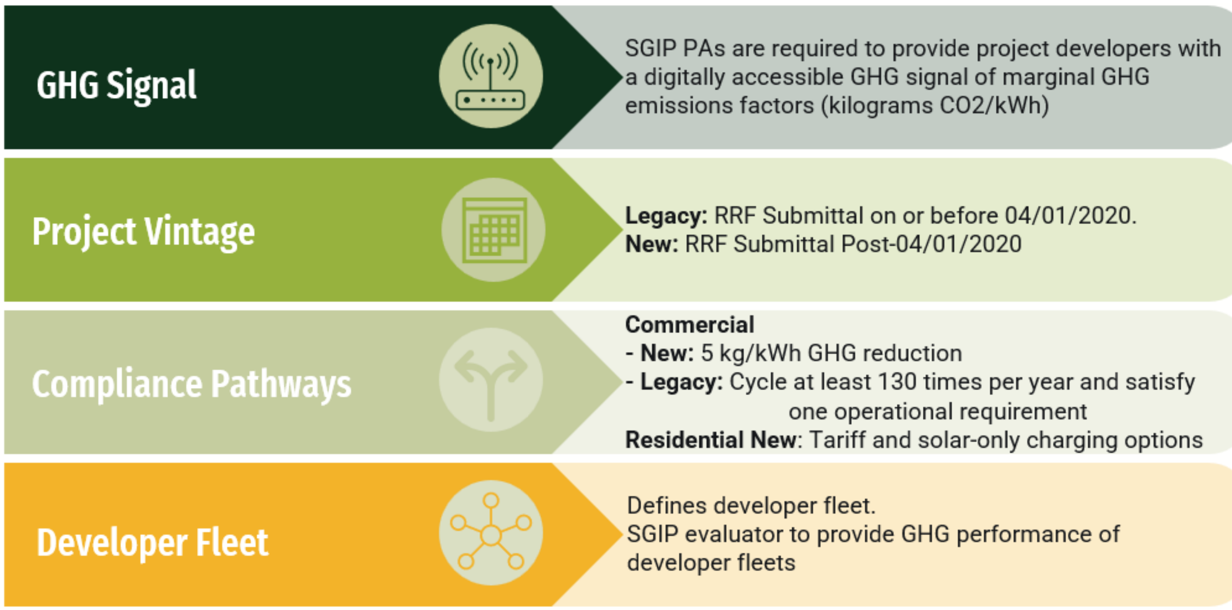




Storage Composition by Developer Legacy Status

Decision 19-08-001 approved the greenhouse gas emission reduction requirements for the SGIP storage budget. Figure 3-17 highlights the key provisions set forth in the decision.

FIGURE 3-17: GREENHOUSE GAS EMISSIONS REDUCTION REQUIREMENTS FROM D.19-08-001



This decision was approved in 2019 and was instituted in PY 2020, so the GHG emission reporting for this impact evaluation is limited to Legacy nonresidential and residential developer fleets. New nonresidential and residential projects are ALL within their second or third year of permanency in 2023, so GHG reporting is NOT required for this evaluation, per the decision. However, the M&E plan calls for an impact evaluation of the program, so New residential and nonresidential systems need to be included in the context of program impacts – the evaluator is just not required to include these systems in the fleet level GHG emissions reporting.

Figure 3-18 presents the over 44,000 residential systems subject to evaluation for this 2023 study by payment year and vintage. With the significant influx of new funding and completed applications after April 1, 2020, there are now over 20,000 New systems requiring evaluation, along with 16,000 Legacy systems. Developer GHG impacts are required for the 16,000 projects, if they constitute a developer fleet, and while there is no developer specific GHG reporting requirement for the 29,000 New systems until year five of permanency, Verdant developed impacts for them to meet overall program impact evaluation goals.

FIGURE 3-18: NEW VERSUS LEGACY RESIDENTIAL SGIP PROJECTS

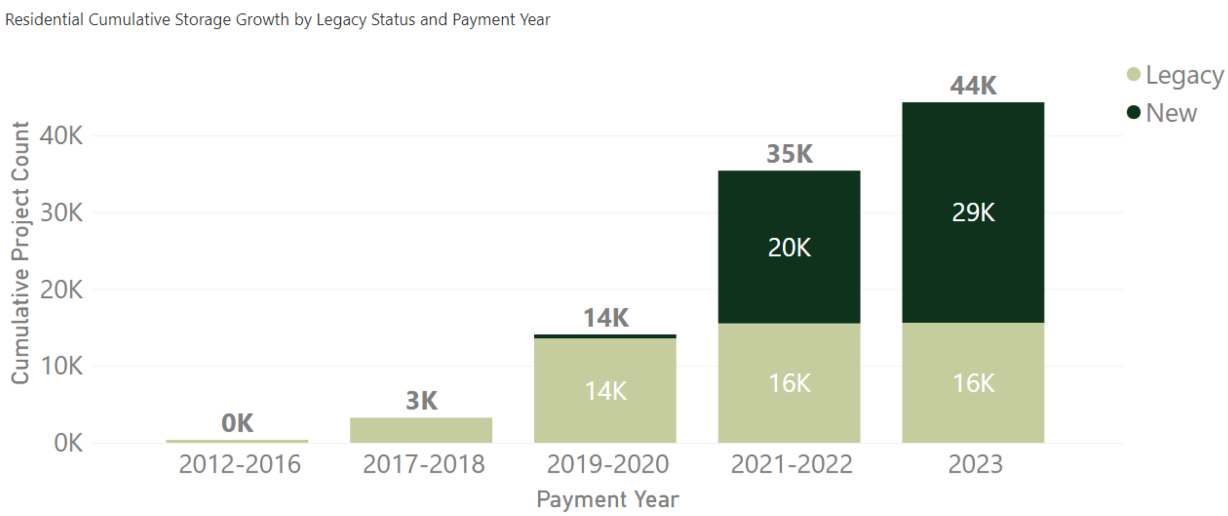
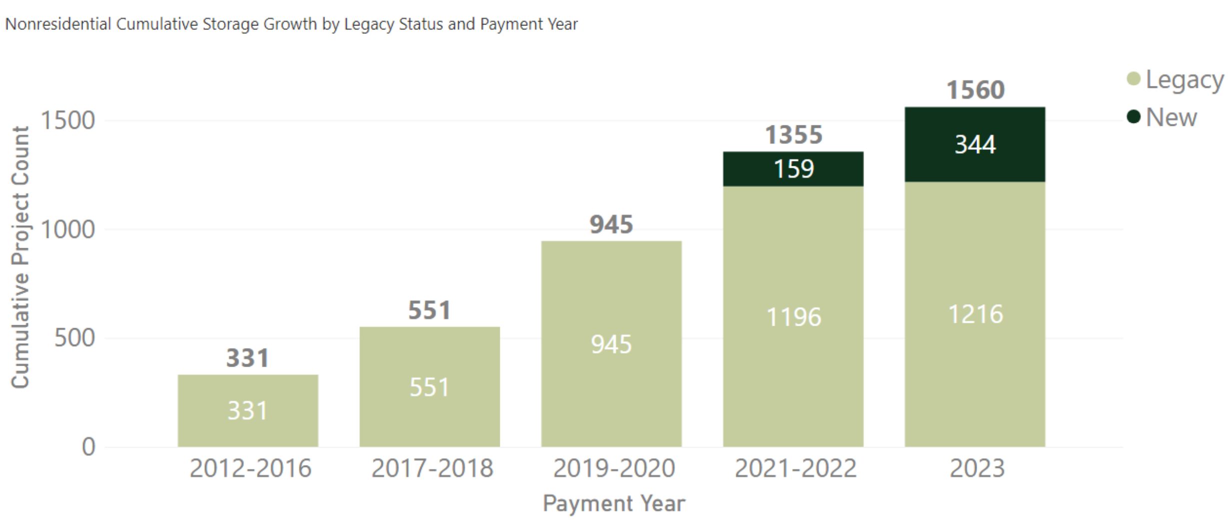


Figure 3-19 presents the New versus Legacy status for the nonresidential sector. Given the greater average lag times between the program initial RRF program application submittal to eventual upfront incentive payment, and the recent slowing of nonresidential application submissions, 88% of nonresidential projects subject to evaluation in this study are Legacy. There are 1,560 nonresidential systems subject to evaluation in 2023, with 1,216 of those defined as Legacy systems. Only 344 projects in this sector had completed their application on or after April 1, 2020 *and* received their upfront incentive payment prior to the end of 2023.

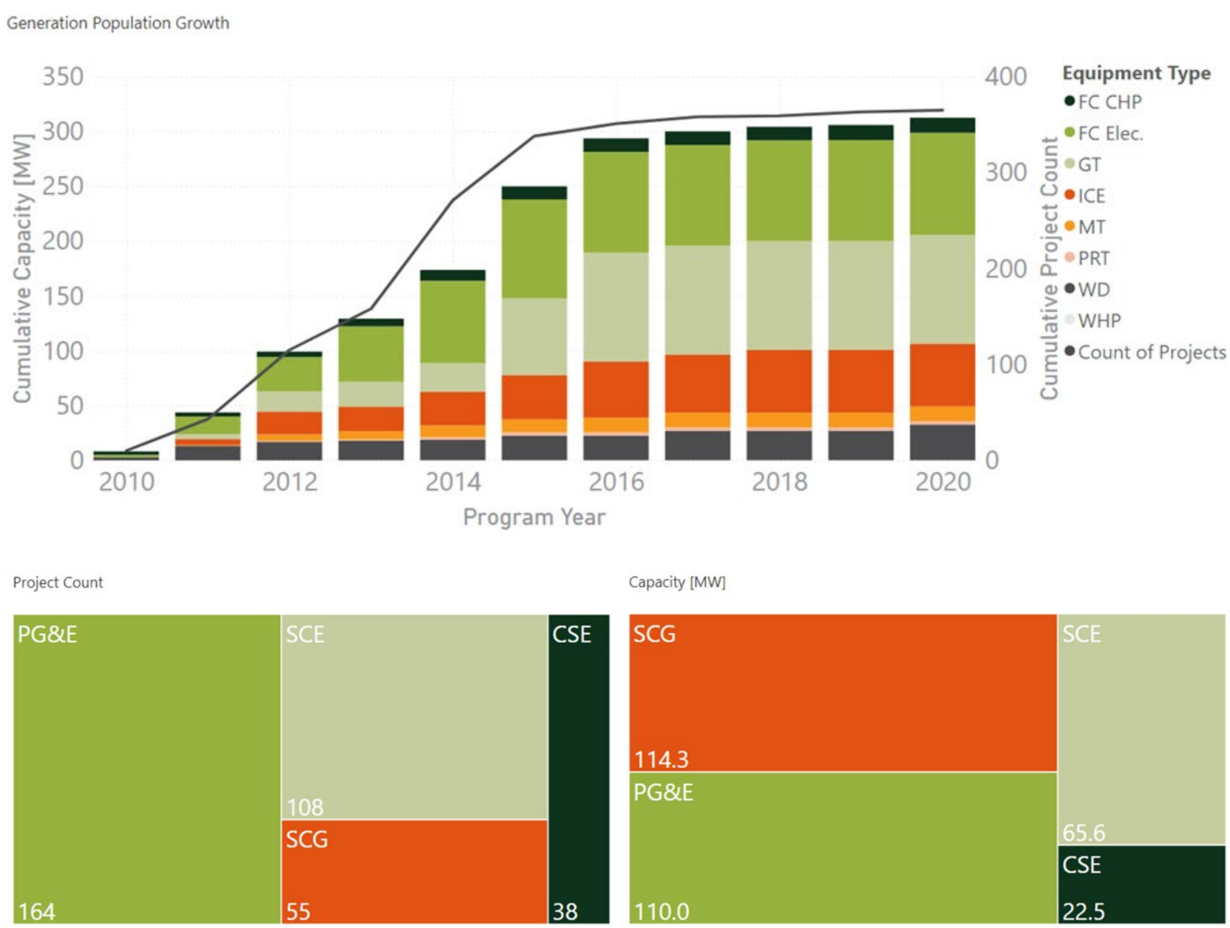
FIGURE 3-19: NEW VERSUS LEGACY NONRESIDENTIAL SGIP PROJECTS



3.2 COMPOSITION OF SGIP GENERATION POPULATION

Figure 3-20 highlights the growth in SGIP incentivized generation capacity since program inception through 2023, for projects still within their permanency period. The program year (PY) on the horizontal axis represents the year a project applied to the SGIP. By the end of 2023, the SGIP provided incentives for 365 generation projects still within their permanency period, representing 312 MW of incentivized capacity. Due to changes in the SGIP for generation technologies, since 2017, the number of project applications resulting in incentive payments has dropped off significantly. This dramatic decrease in projects shows the impact changes in program fuel requirements have had on participation levels. As can be seen below, the last paid projects were PY 2020 projects.

FIGURE 3-20: SGIP GENERATION CUMULATIVE GROWTH BY EQUIPMENT TYPE AND PROGRAM YEAR



Note: **FC CHP:** CHP Fuel Cell, **FC Elec.**: All-Electric Fuel Cell, **GT:** Gas Turbine, **ICE:** Internal Combustion Engine, **MT:** Microturbine, **PRT:** Pressure Reduction Turbine, **WD:** Wind Turbine, **WHP:** Waste Heat to Power

Table 3-4 shows the number of paid projects that fall under the newer SGIP rules, requiring an escalating percentage of renewable fuel. Since PY 2017, only 14 projects have been paid, half of them being wind turbine projects.

TABLE 3-4: SGIP GENERATION PAID PROJECTS SINCE 2017

Equipment Type	2017		2018		2019		2020		Total	
	Count	MW	Count	MW	Count	MW	Count	MW	Count	MW
Fuel Cell Electric	--	--	--	--	1	0.20	1	1.00	2	1.20
Fuel Cell CHP	--	--	--	--	1	1.40	--	--	1	1.40
Internal Combustion Engine	3	1.91	1	4.20	--	--	--	--	4	6.11
Wind	4	4.44	--	--	2	0.02	1	5.64	7	10.11
Total	**7**	**6.36**	**1**	**4.20**	**4**	**1.62**	**2**	**6.64**	**14**	**18.82**

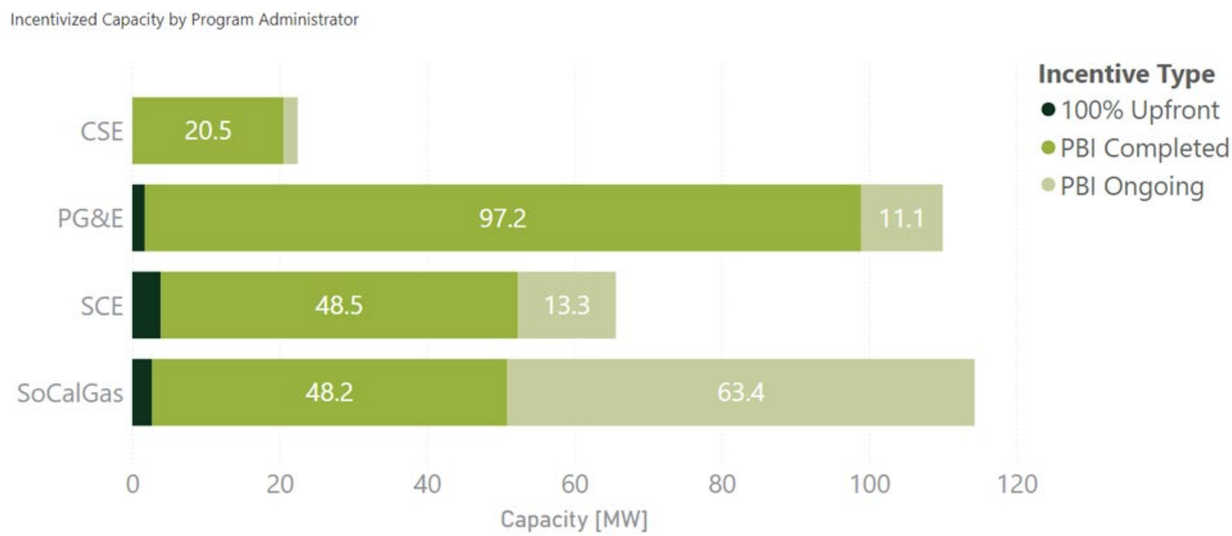
PG&E accounted for most of the generation projects in the population, with a total of 164 projects. Table 3-5 displays both the project count and the rebated capacity by technology. Almost 50% of these, by project count, were fuel cell electric equipment. While SCE made up the next largest share of projects, at 108, SoCalGas made up the largest share of rebated capacity due to the large gas turbine projects they incentivized.

TABLE 3-5: PROJECT COUNT AND INCENTIVIZED CAPACITY BY PROGRAM ADMINISTRATOR

Equipment Type	CSE		PG&E		SCE		SoCalGas	
	Count	MW	Count	MW	Count	MW	Count	MW
Fuel Cell Electric	24 *(63%)*	7.7 *(34%)*	101 *(62%)*	43.3 *(39%)*	78 *(72%)*	24.1 *(37%)*	35 *(64%)*	18.1 *(16%)*
Fuel Cell CHP	5 *(13%)*	1.7 *(8%)*	5 *(3%)*	3.5 *(3%)*	3 *(3%)*	1.6 *(2%)*	6 *(11%)*	7.0 *(6%)*
Gas Turbine	2 *(4%)*	9.0 *(40%)*	1 *(1%)*	9.6 *(9%)*	--	--	5 *(9%)*	80.5 *(70%)*
Internal Combustion Engine	4 *(11%)*	2.0 *(9%)*	32 *(20%)*	29.1 *(26%)*	10 *(9%)*	21.3 *(32%)*	5 *(9%)*	4.8 *(4%)*
Microturbine	--	--	10 *(6%)*	5.3 *(5%)*	4 *(4%)*	4.3 *(7%)*	4 *(7%)*	3.9 *(3%)*
Wind	1 *(3%)*	1.0 *(4%)*	12 *(7%)*	18.5 *(17%)*	8 *(7%)*	13.1 *(20%)*	--	--
Pressure Reduction Turbine	2 *(5%)*	1.0 *(5%)*	2 *(1%)*	0.7 *(1%)*	5 *(5%)*	1.3 *(2%)*	--	--
Waste Heat to Power	--	--	1 *(1%)*	0.1 *(0%)*	--	--	--	--
Total	**38** ***(100%)***	**22.5** ***(100%)***	**164** ***(100%)***	**110.0** ***(100%)***	**108** ***(100%)***	**65.6** ***(100%)***	**55** ***(100%)***	**114.3** ***(100%)***

All generation projects greater than 30 kW are required to take performance-based incentives, meaning that 50% of the incentive is paid up front, and the remaining 50% is paid over 5 years, depending on how the system is performing. However, prior to PY 2011, all projects received the entire incentive up front upon project completion. Figure 3-21 below highlights the incentivized capacity by Program Administrator and by incentive type. Most of the projects in the generation population were once PBI projects which have now expired and are past their 5-year reporting requirements and have had all incentives paid out. CSE and PG&E still have a larger share of projects which received capacity-based incentives than those that are still within their PBI payment period.

FIGURE 3-21: INCENTIVIZED CAPACITY BY PROGRAM ADMINISTRATOR AND INCENTIVE TYPE



4 SGIP PERFORMANCE METRICS AND IMPACTS

The primary objective of this study is to evaluate energy, environmental, and financial impacts of generation systems and energy storage systems incentivized through the Self-Generation Incentive Program (SGIP) and operating during calendar year 2023. Results of analysis of metered data only are presented in Sections 4.1 through 4.6. Table 4-1 summarizes the energy storage population subject to evaluation, along with the number of sampled projects.

TABLE 4-1: 2023 SGIP ENERGY STORAGE POPULATION AND SAMPLE OF PROJECTS

Sector	Payment Year	Project Status	Population N	Sample n	In Sample Impacts	In Population Impacts
Nonresidential	2017 Prior	Decommissioned	197	197	No	Yes
		Operable	236	88	Yes	Yes
	2018-2022	Decommissioned	25	25	No	Yes
		Operable	897	748	Yes	Yes
	2023	Operable	205	153	Yes	Yes
	Total		*1,560*	*1,211*		
Residential	2017 Prior	Unknown[27]	394	-	No	No
	2018-2022	Operable	35,008	1,822	Yes	Yes
	2023	Operable	8,895	255	Yes	Yes
	Total		*44,297*	*2,077*		
Total			**45,857**	**3,288**		

The metered sample of projects informs the impact analyses and optimization modeling conducted for this study. Decommissioned projects are of particular importance when examining the program impacts and results from the metered sample of projects. Our team has identified, from past and current evaluation activities, systems that are offline or have been decommissioned. The forthcoming analyses on

[27] These projects represent those receiving incentives before 2018, but their data acquisition systems are antiquated and metered data cannot be accessed.

observed system performance exclude the impacts from these projects. These systems are no longer installed and operable, so their non-performance is known and would misrepresent the impacts generated from SGIP storage systems which are currently installed and operable. However, given the cumulative nature of these evaluations, their non-performance is captured when developing program population impacts.

Another important consideration, as highlighted in the sidebar below, is to calculate impacts by classifying and quantifying the counterfactual baselines.

Counterfactual Baselines: Calculation of impacts, such as change in coincident peak electricity demand measured at the utility meter, requires assumptions about what a customer's electricity consumption at the meter would have been had they *not* installed the SGIP system. These assumptions describe an unobservable, counterfactual, non-SGIP baseline that is compared to electricity consumption observed to estimate impacts of the SGIP system at the utility meter.

$$Impacts = UtilityMeterLoad_{with\ SGIP\ system} - UtilityMeterLoad_{counterfactual}$$

For this impacts evaluation, the key assumption underlying the impacts analytic methodology is that participation in the SGIP was not responsible for any changes in the quantity or timing of electricity loads for end uses ***LoadsEndUses*** (e.g., lighting, HVAC) that might have occurred after installation of the SGIP system, or for any changes in the quantity or timing of electricity production (***PV)*** of any photovoltaic system capacity that might be present. The values of ***LoadsEndUses*** and ***PV*** are thus identical for the counterfactual and for the observed conditions (with SGIP system). That is:

$$UtilityMeterLoad_{counterfactual} = LoadsEndUses - PV$$

$$UtilityMeterLoad_{with\ SGIP\ system} = LoadsEndUses - PV - SGIP_{engo}$$

$$Impacts = \left(LoadsEndUses - PV - SGIP_{engo}\right) - \left(LoadsEndUses - PV\right) = -SGIP_{engo}$$

The impacts of the SGIP system on coincident peak electricity consumption measured at the utility meter are simply equal to the negative of SGIP system output. This is an intuitive result describing the situation where SGIP system power output serves to decrease the amount of utility power required to satisfy end use loads. Where ***SGIP$_{engo}$*** is defined as SGIP system power

4.1 OBSERVED PERFORMANCE METRICS

The effectiveness of generation systems and energy storage systems in producing impacts depends largely on energy conversion efficiencies and operational choices governing equipment utilization. Metered data were analyzed to develop measures of efficiencies and utilization of SGIP systems operating during 2023. Overall system efficiencies depend on the combined effects of efficiencies of many subsystems. For example, gas turbine generator system efficiency depends on fuel combustion efficiency, electric generator efficiency, and numerous other component efficiencies. Battery energy storage efficiency depends on electro-chemical efficiencies associated with charge/discharge cycles, voltage transformation efficiencies and numerous other component efficiencies. However, overall system efficiencies are of interest to end users and are the efficiencies we present results for in this section.

The general term 'utilization' summarizes the combined effects of various factors governing how much an SGIP system is used, which is closely related to the impacts it can produce. Utilization may encompass matters of choice (e.g., operating hours, operating mode selection), as well as resource availability in the case of wind turbine systems. Capacity factor is one performance metric customarily used to measure utilization. Capacity factors are calculated as the ratio of system energy output during any particular period of time to the maximum possible quantity of energy the system could have output during that period of time. Capacity factors for generation systems and energy storage systems are presented below. A second utilization metric is used for battery energy storage: charge/discharge cycle rate, with the total number of cycles per year being of most interest.

4.1.1 Energy Storage Performance Metrics

Verdant reviewed three performance metrics within the SGIP –roundtrip efficiency (RTE), capacity factor (CF) and annual energy storage cycling – to better quantify the efficiency and utilization of energy storage technologies during 2023. Furthermore, we present if and how efficiencies and utilization differ based on the age of the system, system capacity, budget category, facility type (for nonresidential installations), and presence of on-site solar PV generation.

Energy Storage Efficiency

Roundtrip efficiency (RTE) is measured as the total kWh discharge of the system divided by the total kWh charge and is an eligibility requirement for the SGIP.[28] The RTE can be calculated as a single-cycle RTE, which captures the energy losses associated with AC-DC power conversion, and over a given time to also capture operational parasitic loads. This evaluation quantifies the latter, where efficiency is calculated for each system over the whole period for which dispatch data were available and deemed verifiable.

EQUATION 4-1

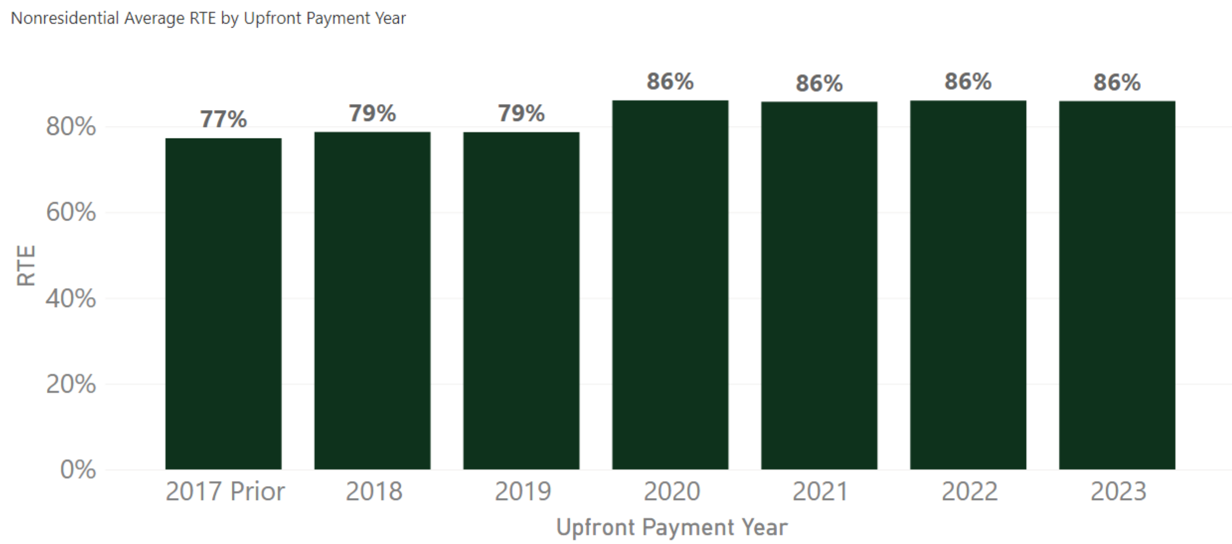
$$Roundtrip\ Efficiency = \frac{\sum kWh\ Discharge\ (kWh)}{\sum kWh\ Charge\ (kWh)}$$

Figure 4-1 presents the average RTE for installed and operable nonresidential systems in 2023 by upfront payment year. We observe an average RTE of 77% in 2023 for projects receiving their upfront incentive

28 Energy storage systems must maintain a round trip efficiency equal to or greater than 69.6% in the first year of operation in order to achieve a ten-year average round trip efficiency of 66.5 percent, assuming a 1% annual degradation rate (Appendix E of the aforementioned SGIP Handbook).

payment in 2017 and prior. We observe a trend in increased efficiency for systems rebated more recently – with systems receiving incentives in 2020 onward exhibiting an RTE of 86% on average.

FIGURE 4-1: AVERAGE 2023 RTE FOR NONRESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR



We also examined the distribution of project specific RTEs across incentive payment year (Figure 4-2). These boxplots present the mean RTE (black circle) along with the minimum, maximum, quartile, and median values. We observe not only increases in average and median RTE values with more recently incentivized projects, but less variation in project RTEs as well. An RTE of 0% signifies that the system was non-operational and the total 2023 discharge was 0 kWh (51 projects or 5% of projects). Verdant verified the performance of each project as part of the QA/QC process, and the metered data for systems exhibiting low or zero RTE confirm this non-performance. Most of these non-operational systems applied to the program in earlier years (2012-2016) and represent a developer experiencing more recent decommissioning. Verdant will continue to track these projects in future evaluations to determine if systems were off-line or non-operational just for a given time, or if the non-performance is a harbinger for future decommissioning.

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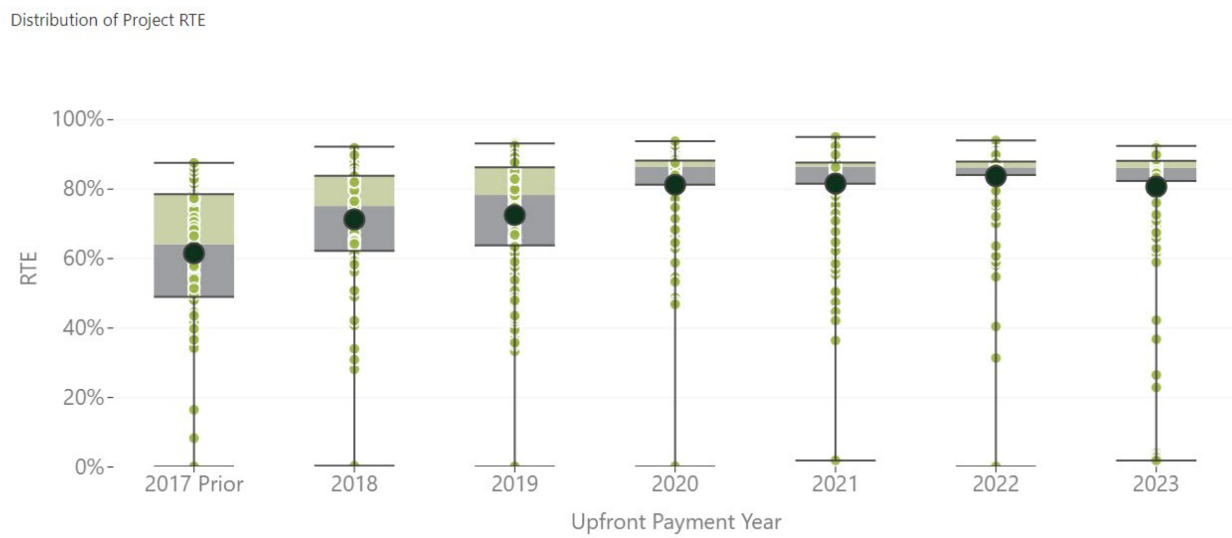
FIGURE 4-2: DISTRIBUTION OF 2023 RTE FOR NONRESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR



Residential RTEs exhibit similar average RTEs across payment year to the nonresidential sector, but less variability across project and payment year. Average efficiencies are all above 80% (Figure 4-3). Unlike the nonresidential sector, all sampled residential projects applied to the program in 2017 or after and received their upfront payments in 2018 or thereafter.

Boxplots in

Figure 4-4 confirm the narrow spread in project specific RTEs. Verdant did observe some low and non-operational systems within the sample of projects. This non-performance suggests these systems were operating in exclusive backup mode. Roughly 6% of sampled residential systems were found to be under-utilized or in backup-only mode during 2023.

FIGURE 4-3: AVERAGE 2023 RTE FOR RESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR

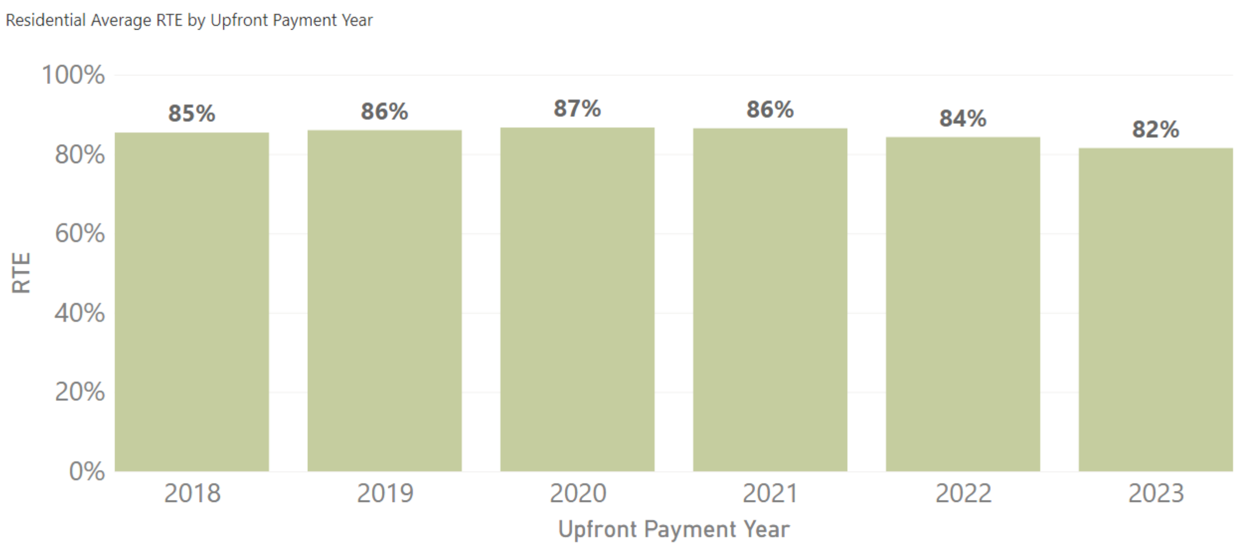
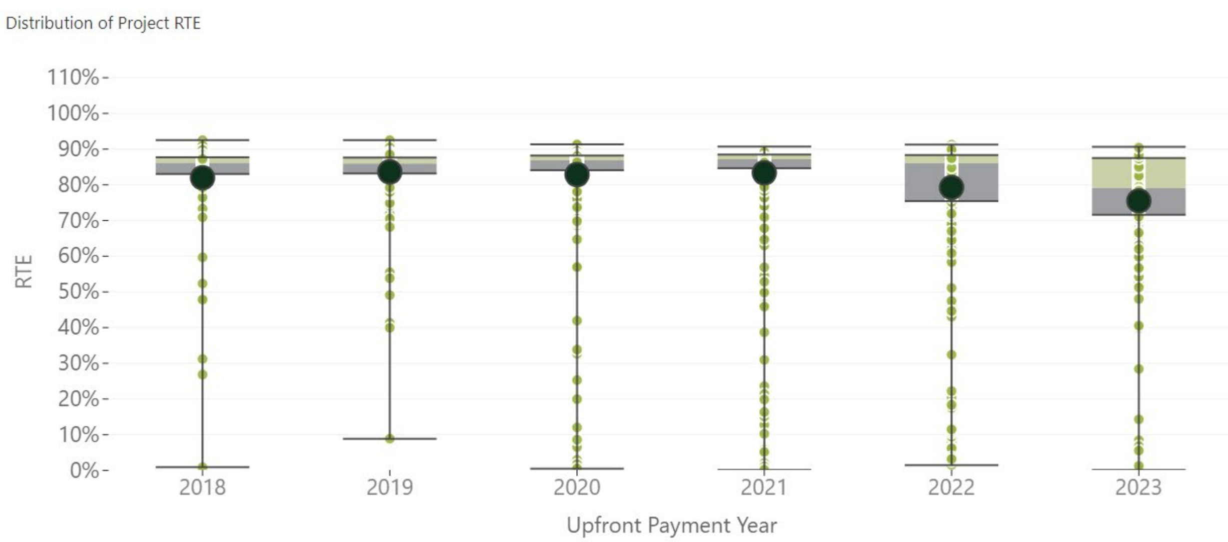


FIGURE 4-4: DISTRIBUTION OF 2023 RTE FOR RESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR



Energy Storage Utilization

Unlike generating technologies, like a fuel cell which can operate at or near full capacity nearly continuously, energy storage discharge is limited by the size of the inverter and the kWh capacity of the battery along with the battery state-of-charge (SOC). Example capacity factors are provided in the figure to the right to better understand utilization as a function of discharge capacity – in percent power discharge over the course of an hour – and battery duration. In practice, a five-hour battery discharging at 100% discharge capacity once a day would have a 21% capacity factor.

Capacity Factor by System Duration and % kW Hourly Discharge

kW Discharge	1 hr	2 hrs	3 hrs	4 hrs	5 hrs
10%	0%	1%	1%	2%	2%
20%	1%	2%	3%	3%	4%
40%	2%	3%	5%	7%	8%
60%	3%	5%	8%	10%	13%
80%	3%	7%	10%	13%	17%
100%	4%	8%	13%	17%	21%

Hourly discharge capacity is also predicated on the underlying storage operating mode – TOU arbitrage (with or without export), demand charge reduction, or (solar) self-consumption. If a battery is programmed for self-consumption – zeroing out imported load as much as possible – battery discharge is limited to underlying BTM consumption and may represent only a fraction of system capacity within a given hour. On the other hand, TOU arbitrage may result in daily cycling during the four summer months (June-September) but none during the other eight months of the year, due to low peak to off-peak rate differentials.

The capacity factors for the sample of nonresidential storage systems are presented below in Figure 4-5 by upfront payment year. To better understand the range in system utilization during the year, project distributions follow in Figure 4-6. Capacity factors are positively correlated to RTEs – an under-utilized storage system (or system with a low capacity factor) will generally exhibit a low RTE and greater utilization (i.e. higher capacity factor) indicates greater system efficiency (i.e. a high RTE). Capacity factors range from as low as 0% (indicating non-performance) to as high as 32%. The greater capacity factor for projects paid in 2022 reflects a large fleet of longer duration batteries installed in the Equity Resiliency Budget (ERB) category.

FIGURE 4-5: AVERAGE 2023 CAPACITY FACTOR FOR NONRESIDENTIAL SECTOR BY PAYMENT YEAR

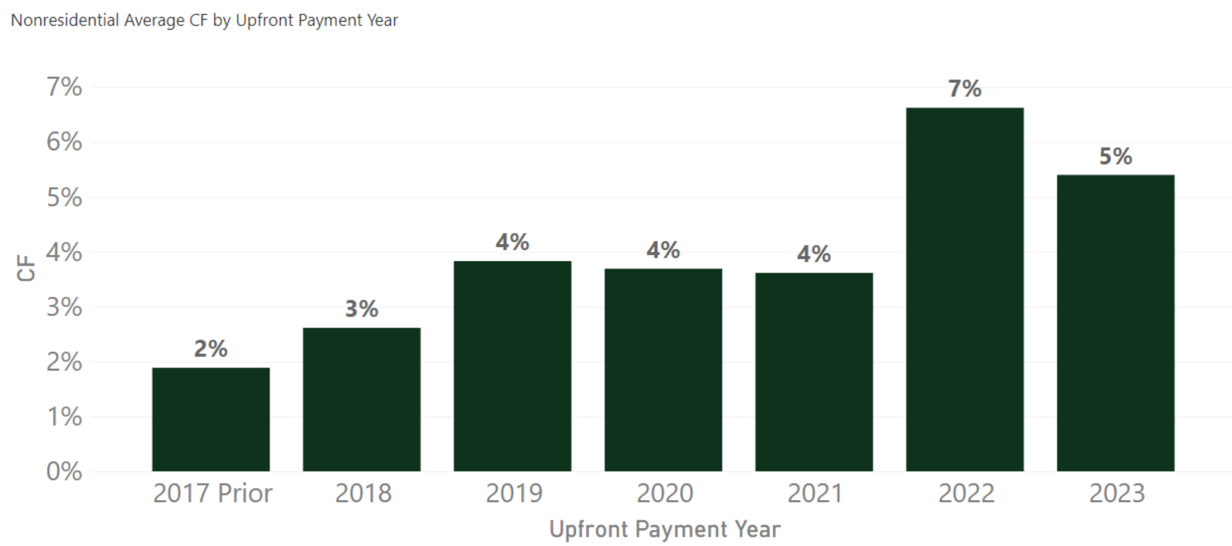
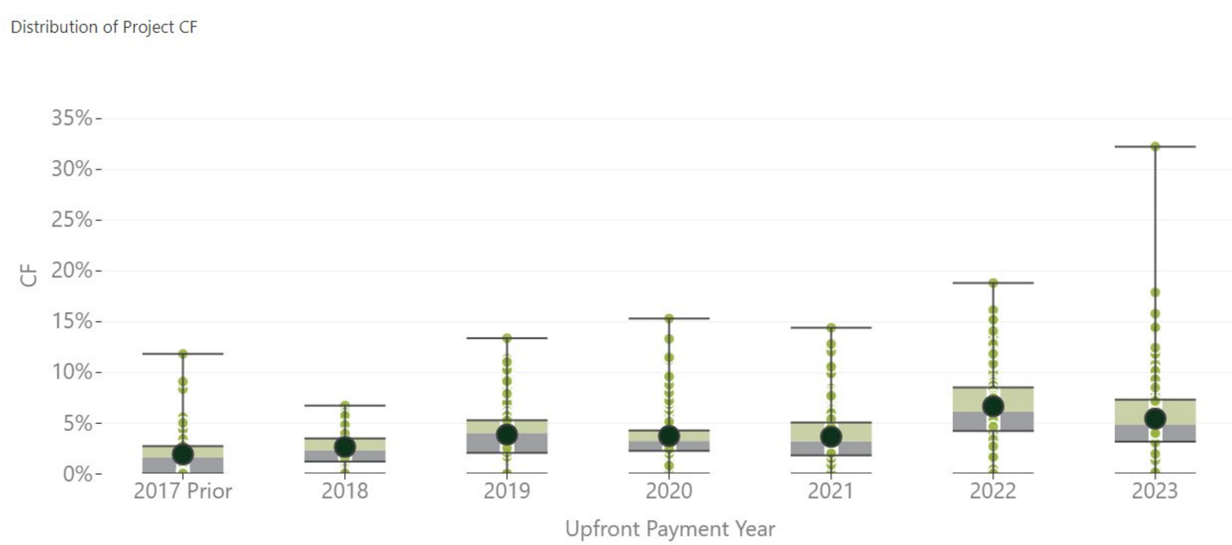
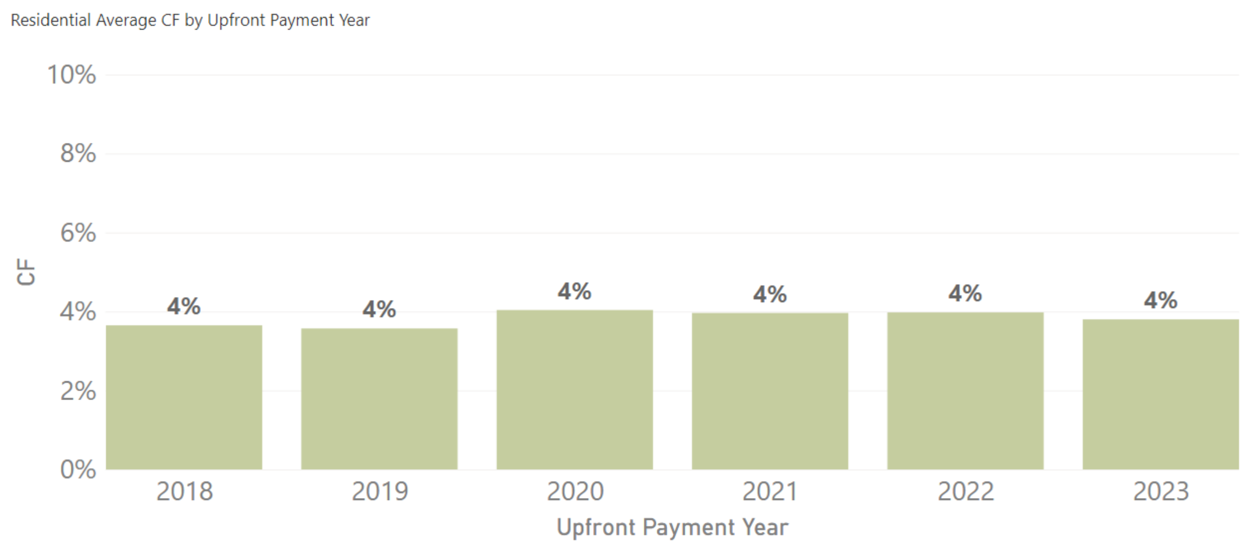


FIGURE 4-6: DISTRIBUTION OF 2023 CAPACITY FACTOR FOR NONRESIDENTIAL SECTOR BY PAYMENT YEAR



Average capacity factors and capacity factor distributions in the residential sector are presented below in Figure 4-7 and Figure 4-8. Residential capacity factors don't exhibit much variability across payment year, but we do observe inter-project variability.

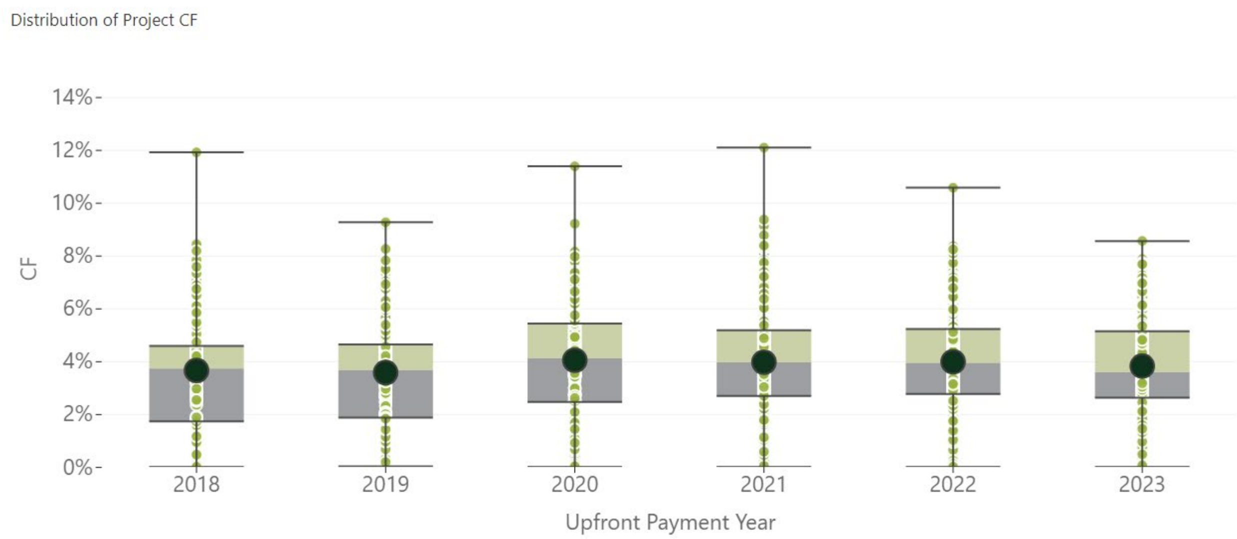
FIGURE 4-7: 2023 AVERAGE CAPACITY FACTOR FOR RESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR



Residential systems are generally operating in one of two modes – TOU arbitrage or self-consumption. For systems operating in either mode (and not exporting), discharge is limited to underlying customer load. For TOU arbitrage, the battery will generally discharge only during the customer on-bill peak period to zero out utility imports. Once the battery reaches a minimum state-of-charge (SOC) the battery will stop discharging. Self-consumption is a similar operation, but discharge may extend outside of on-peak billed periods. Either way, utilization is limited to the size of the battery relative to customer BTM consumption.

However, utilization tends to increase for systems conducting arbitrage and exporting additional capacity not being used to service load. In these circumstances the discharge is not limited to customer load, so additional capacity can be utilized and returned to the grid much like excess solar generation.

FIGURE 4-8: DISTRIBUTION OF 2023 CAPACITY FACTOR FOR RESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR



The second utilization metric tracked within the SGIP is cycling or "number of discharges" and is defined as the total kWh discharge of the system divided by the energy (kWh) capacity of the system. It represents a proxy for total number of discharge cycles throughout the year for a given system.[29] If a two-hour, 50-kW system (100 kWh) discharged 60% of capacity once a day, every day throughout the year, this would represent roughly 219 cycles – (50 kW x 2hr x 0.6 x 365) / 100 kWh. While capacity factors are generally greater for longer duration batteries (all else being equal), the cycling metric is proportional to the size of the battery – a two-hour battery fully discharging once a day will cycle the same amount as a 5-hour battery discharging fully once a day. With similar utilization, a storage system can exhibit an 80% RTE during one month of activity or throughout a full year of operation. The same is true for a system capacity factor. A system can exhibit a 10% capacity factor during one peak hour, or throughout a month or year because it's based on

Cycles by System Duration and % kW Hourly Discharge

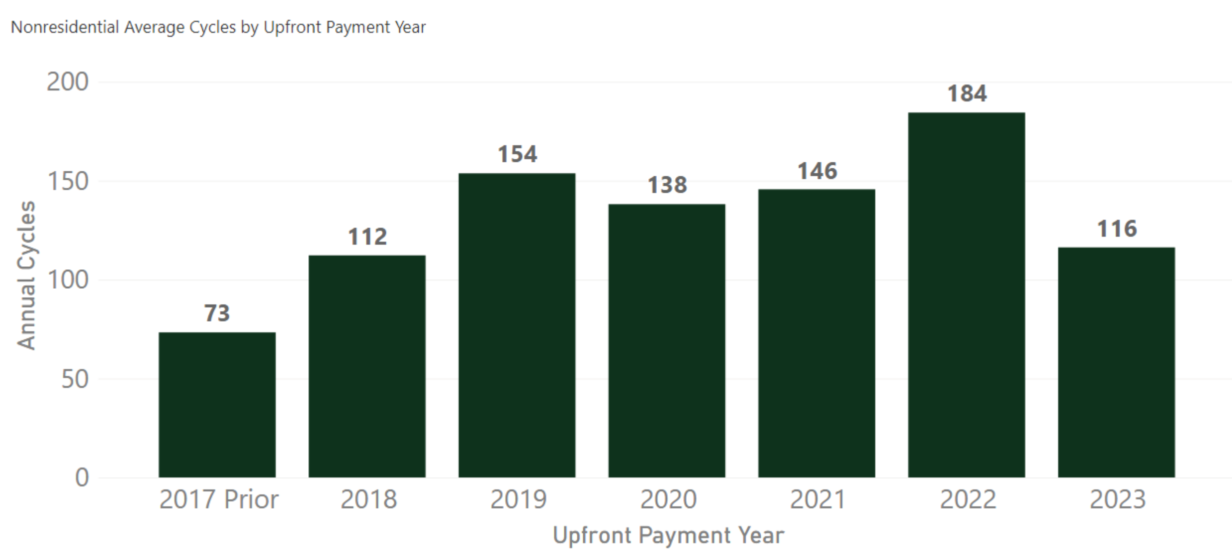
kW Discharge	1 hr	2 hrs	3 hrs	4 hrs	5 hrs
10%	37	37	37	37	37
20%	73	73	73	73	73
40%	146	146	146	146	146
60%	219	219	219	219	219
80%	292	292	292	292	292
100%	365	365	365	365	365

[29] The 2021 SGIP Handbook requires commercial systems to discharge a minimum of 130 full discharges per year and residential systems to discharge a minimum of 52 full discharges per year. Each time a system discharges it does not have to be a discharge of 100% capacity. Rather, the full discharge definition equates to the aggregate amount of discharges over the year (Sections 5.2.3 and 5.2.9).

operational periods. Cycling is predicated on the magnitude of hourly discharge, but also the length of time in which the system has been operating.

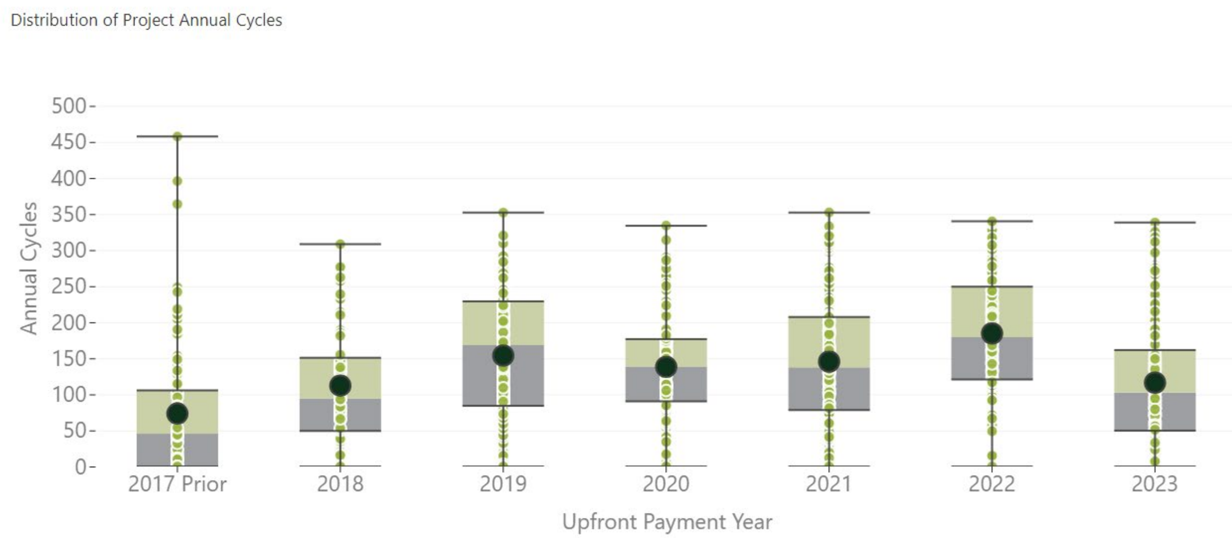
This latter point is evident in Figure 4-9 below, which summarizes annual cycling in the nonresidential sector by payment year. We observe an increase in annual utilization, from an average of 73 cycles for projects paid in 2017 or earlier to 184 cycles for projects paid in 2022. However, utilization drops again for 2023 projects. The reason we observe a reduction in cycles for projects incentivized in 2023 is the reduced length of time in which a system may have been operating. Verdant develops partial year impacts for systems receiving incentives mid-way through a calendar year. We do not extrapolate one full year of data from partial year impacts. So, while a system may receive their incentive and begin normal operations in August of 2023 and exhibit an 80% RTE and 8% CF during that operational period, the annual cycles are calculated off four or five months of metered data, rather than a full calendar year.

FIGURE 4-9: 2023 AVERAGE ANNUAL CYCLES FOR NONRESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR



Project distributions in Figure 4-10 also reveal the minimum, maximum, and median values of project utilization in 2023. Of note are projects at or near the top of each whisker with utilization greater than 365. This signifies, on average, a system fully discharging more than once per day throughout the year. Metered storage data confirm this. Some systems are actively cycling during the day without any clear intended purpose, while others are more nuanced and sophisticated – discharging to reduce customer non-coincident peak demand. We observe some systems discharging to keep load below a certain threshold, then charging immediately thereafter, and continuing this pattern during the day.

FIGURE 4-10: DISTRIBUTION OF 2023 CYCLES FOR NONRESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR



Residential systems cycle more than the program minimum of 52 cycles. Systems performing TOU arbitrage or self-consumption may only be discharging 40-60% of available capacity each day. We also observe roughly 99% of residential projects paired with on-site solar PV charging the battery exclusively from solar. The battery will only charge during PV generating hours, so we don't observe the constant daily charge and discharge cycling observed with some nonresidential systems conducting peak shaving. Again, the reduction in cycles for projects receiving incentives in 2023 is likely due to systems with partial year impacts and lower overall cycles as a result.

FIGURE 4-11: 2023 AVERAGE ANNUAL CYCLES FOR RESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR

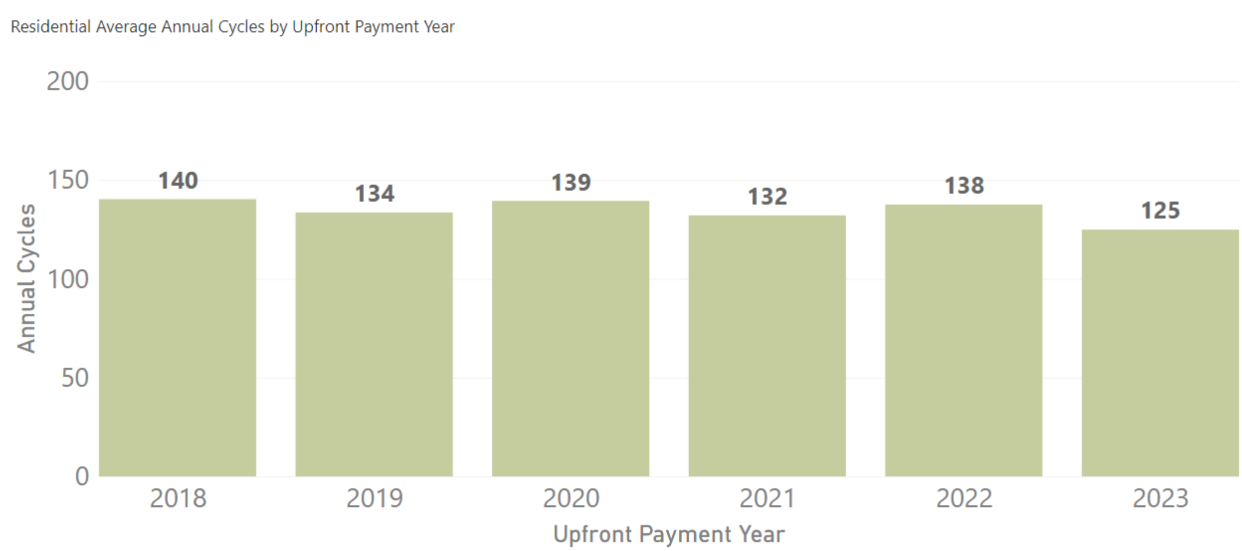
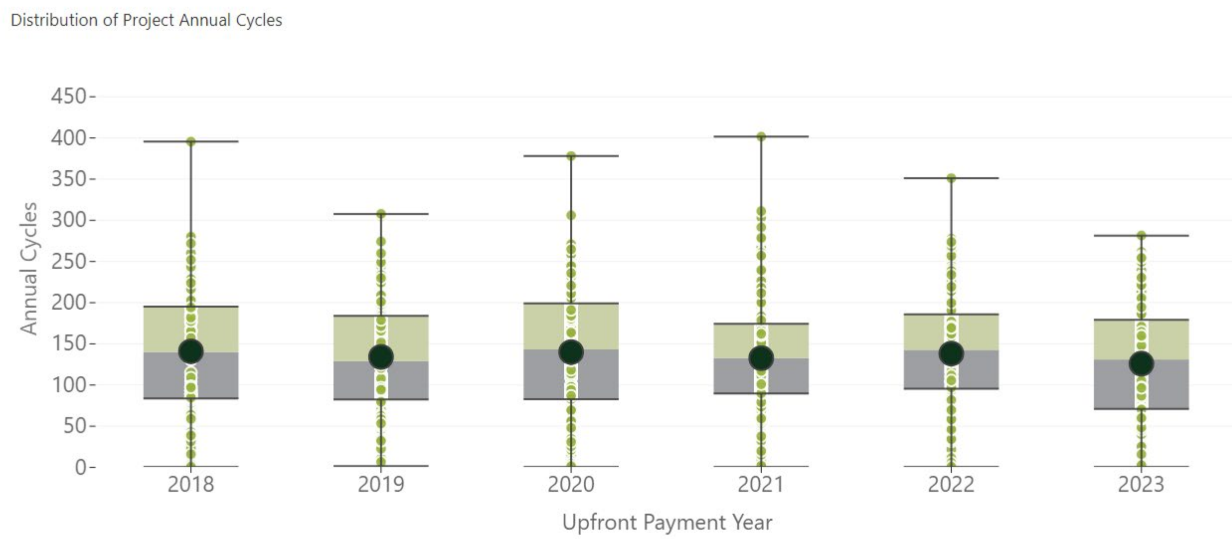


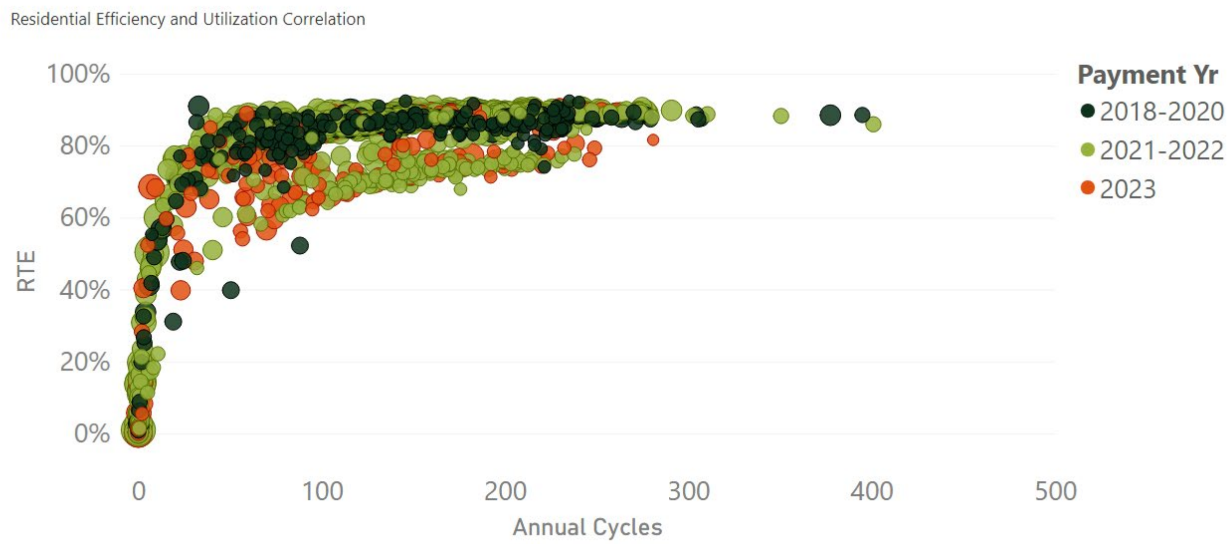
FIGURE 4-12: DISTRIBUTION OF 2023 CYCLES FOR RESIDENTIAL SECTOR BY UPFRONT PAYMENT YEAR



As noted previously, the RTE is a measure of the efficiency of the system – how much energy the system is discharging relative to the amount of energy the system is charging. The discharge frequency is a measure of utilization – how often is the system being discharged to perform different objectives or the total discharge kWh of the system divided by the total capacity kWh of the system. The two are related – if a system is not being utilized then it remains idle and consumes energy without providing any benefits. Depending on its size and location, an idle system is like the equivalent of a large flat screen TV being left on all day. The energy consumption can seem small, but over time, those losses add up and reduce the RTE and any potential environmental benefits of the system. Efficiency is impacted, not only by any battery losses due to AC-DC power conversion but also the parasitic loads associated with system cooling, communications, and other power electronic loads.

When a system is utilized more often, it often has a greater RTE. This relationship is evident in Figure 4-13 and

Figure 4-14: RTE Versus Discharge Cycles for Residential Sector by Upfront Payment Date



where the total number of discharge cycles for each project are plotted against the efficiency or RTE of the system for the nonresidential and residential sectors, respectively. We observe a general increase in RTE (vertical axis) as a system is being utilized more often (i.e. undergoing a higher volume of cycles) (horizontal axis). These figures also highlight the more prevalent inter-project variability in the nonresidential sector compared to residential. The nonresidential sector exhibits a much greater range in storage system capacity than residential systems and are installed in a variety of facility types with differing load shapes and demand requirements.

FIGURE 4-13: RTE VERSUS DISCHARGE CYCLES FOR NONRESIDENTIAL SECTOR BY UPFRONT PAYMENT DATE

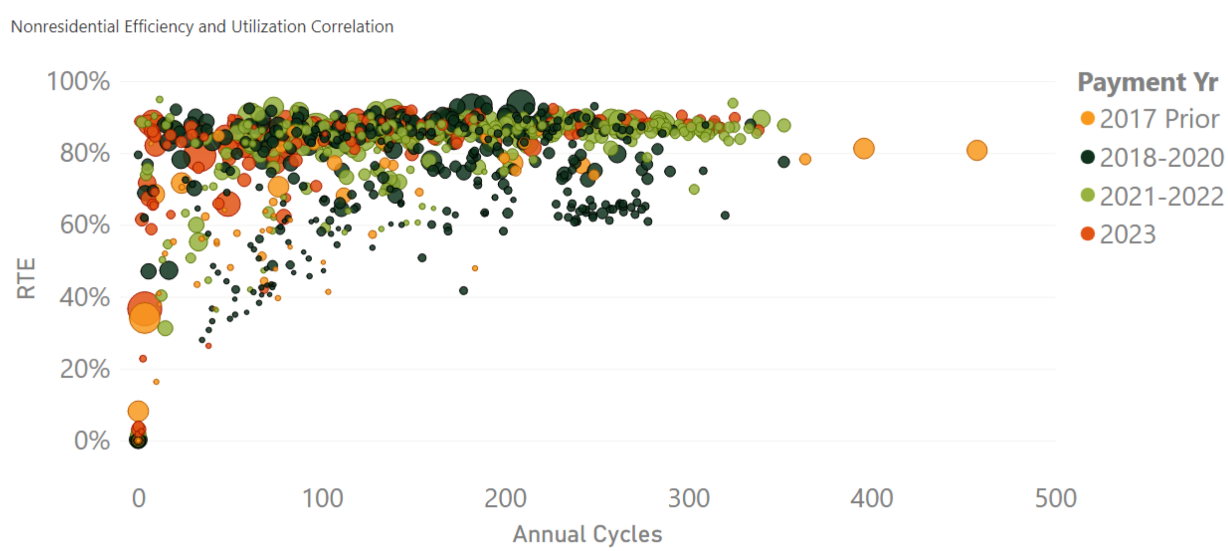
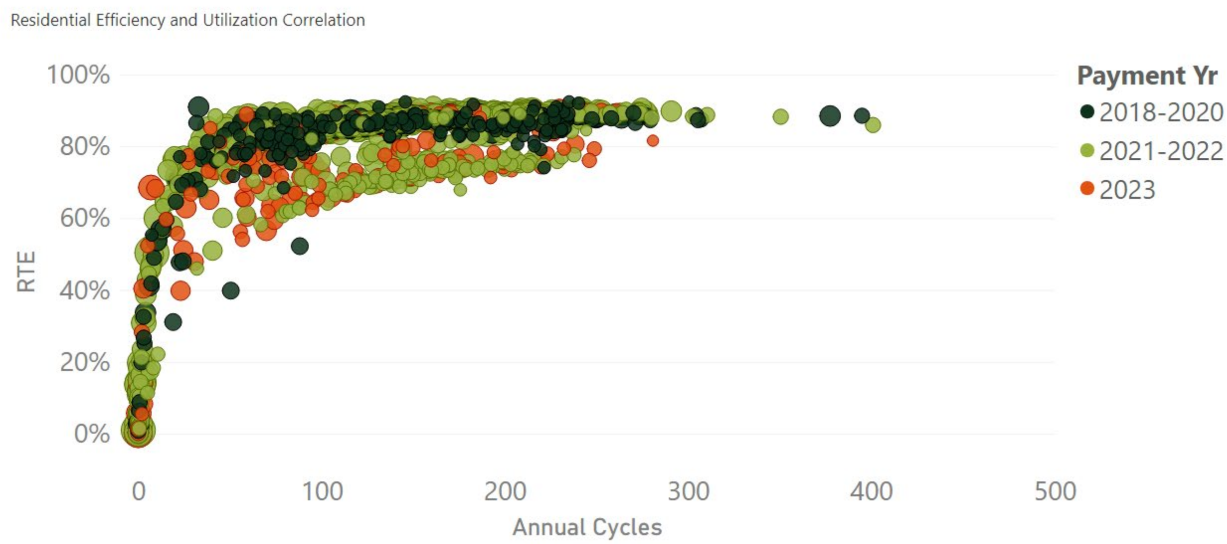


FIGURE 4-14: RTE VERSUS DISCHARGE CYCLES FOR RESIDENTIAL SECTOR BY UPFRONT PAYMENT DATE



Energy Storage Performance Summaries[30]

Metrics like utilization and efficiencies play a key role in determining how storage is providing customer, utility, and environmental benefits within the SGIP. We observe changes in these performance metrics from one evaluation year to the next as program requirements and objectives evolve and energy storage systems become more sophisticated and capable of operating in different modes.[31] Below we summarize the performance metrics discussed above for both the nonresidential and residential sectors, respectively.

[30] The forthcoming performance summaries represent sampled impacts, not those extrapolated to the population like those found in Section 4.6.

[31] One important consideration is program year versus payment year. A project may apply to the program in 2017, but not receive their incentive until 2019. Project design, permitting, system build-out, inspection, etc. take time, especially for larger nonresidential projects. In other words, a project program year may be different than the project payment year.

FIGURE 4-15: SUMMARY OF 2023 NONRESIDENTIAL PERFORMANCE METRICS BY PA

n Prj, Avg kW, Avg kWh, Duration, RTE, CF, Cycles
BY PROGRAM ADMINISTRATOR

Program Administrator	n Prj	Avg kW	Avg kWh	Duration	RTE	CF	Cycles
CSE	187	194	486	2.5	85%	4%	120
PG&E	297	275	739	2.7	85%	5%	152
SCE	450	283	692	2.4	84%	4%	142
SCG	54	402	1,142	2.8	83%	4%	137
Overall	**988**	**270**	**691**	**2.6**	**84%**	**4%**	**140**

FIGURE 4-16: SUMMARY OF 2023 RESIDENTIAL PERFORMANCE METRICS BY PA

n Prj, Avg kW, Avg kWh, Duration, RTE, CF, Cycles
BY PROGRAM ADMINISTRATOR

Program Administrator	n Prj	Avg kW	Avg kWh	Duration	RTE	CF	Cycles
CSE	296	8	21	2.6	86%	4%	144
PG&E	1054	8	22	2.6	85%	4%	128
SCE	593	8	19	2.5	85%	4%	147
SCG	134	8	21	2.6	84%	3%	103
Overall	**2077**	**8**	**21**	**2.5**	**85%**	**4%**	**134**

FIGURE 4-17: SUMMARY OF 2023 NONRESIDENTIAL PERFORMANCE METRICS BY PAYMENT YEAR

n Prj, Avg kW, Avg kWh, Duration, RTE, CF, Cycles
BY PAYMENT YEAR

Payment Year	n Prj	Avg kW	Avg kWh	Duration	RTE	CF	Cycles
2015	14	286	573	2.0	73%	2%	90
2016	23	176	352	2.0	73%	1%	61
2017	51	195	390	2.0	79%	2%	74
2018	75	259	515	2.0	79%	3%	112
2019	227	181	372	2.1	79%	4%	154
2020	103	363	792	2.2	86%	4%	138
2021	162	324	688	2.1	86%	4%	146
2022	180	266	834	3.1	86%	7%	184
2023	153	332	1,182	3.6	86%	5%	116
Overall	**988**	**270**	**691**	**2.6**	**84%**	**4%**	**140**

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FIGURE 4-18: SUMMARY OF 2023 RESIDENTIAL PERFORMANCE METRICS BY PAYMENT YEAR

n Prj, Avg kW, Avg kWh, Duration, RTE, CF, Cycles
BY PAYMENT YEAR

Payment Year	n Prj	Avg kW	Avg kWh	Duration	RTE	CF	Cycles
2018	98	6	14	2.3	85%	4%	140
2019	187	7	16	2.4	86%	4%	134
2020	274	7	18	2.6	87%	4%	139
2021	734	9	24	2.6	86%	4%	132
2022	529	8	21	2.6	84%	4%	138
2023	255	8	19	2.4	82%	4%	125
Overall	**2077**	**8**	**21**	**2.5**	**85%**	**4%**	**134**

FIGURE 4-19: SUMMARY OF 2023 NONRESIDENTIAL PERFORMANCE METRICS BY BUDGET CATEGORY

n Prj, Avg kW, Avg kWh, Duration, RTE, CF, Cycles
BY BUDGET CATEGORY

Budget Category	n Prj	Avg kW	Avg kWh	Duration	RTE	CF	Cycles
2017 Prior	173	249	497	2.0	80%	2%	83
Equity Resiliency	157	257	1,272	4.9	86%	8%	132
Large-Scale Storage	608	284	608	2.1	84%	4%	161
Non-Residential Storage Equity	50	225	558	2.5	86%	4%	107
Overall	**988**	**270**	**691**	**2.6**	**84%**	**4%**	**140**

FIGURE 4-20: SUMMARY OF 2023 RESIDENTIAL PERFORMANCE METRICS BY BUDGET CATEGORY

n Prj, Avg kW, Avg kWh, Duration, RTE, CF, Cycles
BY BUDGET CATEGORY

Budget Category	n Prj	Avg kW	Avg kWh	Duration	RTE	CF	Cycles
All Others	2	10	26	2.6	89%	6%	189
Equity Resiliency	567	11	28	2.6	86%	4%	121
Large-Scale Storage	104	17	43	2.6	85%	3%	104
Small Residential Storage	1404	7	16	2.5	85%	4%	142
Overall	**2077**	**8**	**21**	**2.5**	**85%**	**4%**	**134**

FIGURE 4-21: SUMMARY OF 2023 NONRESIDENTIAL PERFORMANCE METRICS BY PROGRAM YEAR

n Prj, Avg kW, Avg kWh, Duration, RTE, CF, Cycles
BY PROGRAM YEAR

Program Year	n Prj	Avg kW	Avg kWh	Duration	RTE	CF	Cycles
2012	4	294	588	2.0	76%	4%	147
2013	4	15	30	2.0	83%	0%	2
2014	55	260	520	2.0	78%	2%	61
2015	67	296	593	2.0	82%	2%	89
2016	43	177	354	2.0	78%	2%	104
2017	320	202	418	2.1	79%	4%	148
2018	59	447	972	2.2	86%	3%	137
2019	79	373	775	2.1	87%	4%	148
2020	304	286	911	3.2	86%	6%	169
2021	49	322	1,349	4.2	86%	6%	111
2022	4	218	432	2.0	65%	2%	51
Overall	**988**	**270**	**691**	**2.6**	**84%**	**4%**	**140**

FIGURE 4-22: SUMMARY OF 2023 RESIDENTIAL PERFORMANCE METRICS BY PROGRAM YEAR

n Prj, Avg kW, Avg kWh, Duration, RTE, CF, Cycles
BY PROGRAM YEAR

Program Year	n Prj	Avg kW	Avg kWh	Duration	RTE	CF	Cycles
2017	96	7	17	2.5	86%	4%	136
2018	204	7	16	2.3	86%	3%	135
2019	225	8	21	2.6	87%	4%	133
2020	886	9	24	2.6	87%	4%	133
2021	428	8	21	2.6	84%	4%	136
2022	185	7	17	2.3	81%	4%	143
2023	53	7	15	2.3	78%	4%	100
Overall	**2077**	**8**	**21**	**2.5**	**85%**	**4%**	**134**

FIGURE 4-23: SUMMARY OF 2023 NONRESIDENTIAL PERFORMANCE METRICS BY PV PAIRING

n Prj, Avg kW, Avg kWh, Duration, RTE, CF, Cycles
BY ON-SITE GENERATION

On-site Generation	n Prj	Avg kW	Avg kWh	Duration	RTE	CF	Cycles
On-site PV	377	255	611	2.4	82%	4%	158
Standalone	611	280	741	2.6	85%	4%	130
Overall	**988**	**270**	**691**	**2.6**	**84%**	**4%**	**140**

FIGURE 4-24: SUMMARY OF 2023 RESIDENTIAL PERFORMANCE METRICS BY PV PAIRING

n Prj, Avg kW, Avg kWh, Duration, RTE, CF, Cycles
BY ON-SITE GENERATION

On-site Generation	n Prj	Avg kW	Avg kWh	Duration	RTE	CF	Cycles
PV Paired	2055	8	21	2.5	85%	4%	135
Standalone	22	12	31	2.6	80%	1%	48
Overall	**2077**	**8**	**21**	**2.5**	**85%**	**4%**	**134**

FIGURE 4-25: SUMMARY OF 2023 NONRESIDENTIAL PERFORMANCE METRICS BY BUILDING TYPE

n Prj, Avg kW, Avg kWh, Duration, RTE, CF, Cycles
BY BUILDING TYPE

Building Type	n Prj	Avg kW	Avg kWh	Duration	RTE	CF	Cycles
All Others	162	334	874	2.6	85%	4%	105
EV Station	100	240	451	1.9	86%	5%	250
Grocery	66	103	440	4.3	84%	5%	117
Industrial	142	383	837	2.2	84%	3%	129
Office	71	379	823	2.2	87%	3%	109
Retail	73	217	457	2.1	82%	3%	117
School	267	172	420	2.4	80%	4%	153
Utility	107	364	1,349	3.7	86%	6%	125
Overall	**988**	**270**	**691**	**2.6**	**84%**	**4%**	**140**

FIGURE 4-26: SUMMARY OF 2023 RESIDENTIAL PERFORMANCE METRICS BY OPERATING MODE

n Prj, Avg kW, Avg kWh, Duration, RTE, CF, Cycles
BY OPERATING MODE

Operating Mode	n Prj	Avg kW	Avg kWh	Duration	RTE	CF	Cycles
Other/Unknown	16	8	21	2.6	84%	4%	124
Self-Consumption	1323	9	22	2.6	86%	4%	145
TOU Arbitrage	617	7	17	2.4	85%	4%	136
Under-Utilization/Back-up	121	10	25	2.6	50%	0%	10
Overall	**2077**	**8**	**21**	**2.5**	**85%**	**4%**	**134**

4.1.2 Generation Performance Metrics

Verdant reviewed several performance metrics for SGIP generation participants –capacity factor (CF), electrical, thermal and system efficiency, and useful heat recovery – to better quantify the efficiency and utilization of generation technologies throughout 2023. We also reviewed if systems increased or decreased their utilization and efficiency over time by examining how performance changed for projects operating in 2023. Furthermore, we present if and how efficiency and utilization differ based on the type of generation equipment. The metrics were calculated based on observed meter data collected for a sample of projects. Metering rates vary by technology and whether a system uses fuel or recovers heat, and whether electricity, fuel, or heat data were collected. These rates are presented in Appendix C, but electricity generation and fuel consumption rates vary between 26% for Gas Turbines and 81% for all-electric fuel cells, and heat recovery rates between 17% for Gas Turbines and 62% for CHP fuel cells.

Capacity Factor

Energy impacts are a function of generating capacity. Capacity factor (CF) is a metric of system utilization. For generation technologies, the capacity factor is defined as the amount of energy generated during a given period divided by the maximum possible amount of energy that could have been generated during that period. A capacity factor closer to one indicates that the system is being utilized to its maximum potential.

For the majority of SGIP generation projects, systems are intended as baseload resources, meaning they are operated to generate enough electricity to cover the base load needs of a customer. However, host customers often utilize their systems at capacity factors according to their individual needs. Some facilities only need full capacity during weekday afternoons, and some might need full capacity 24/7. Annual capacity factors are useful when comparing utilization between or across varieties of project sizes and technologies. To the extent that SGIP projects are cleaner (regarding greenhouse gases) than the grid energy they displace, high annual capacity factors are desirable. A capacity factor of 1.0 is full utilization regardless of a project's generating capacity.

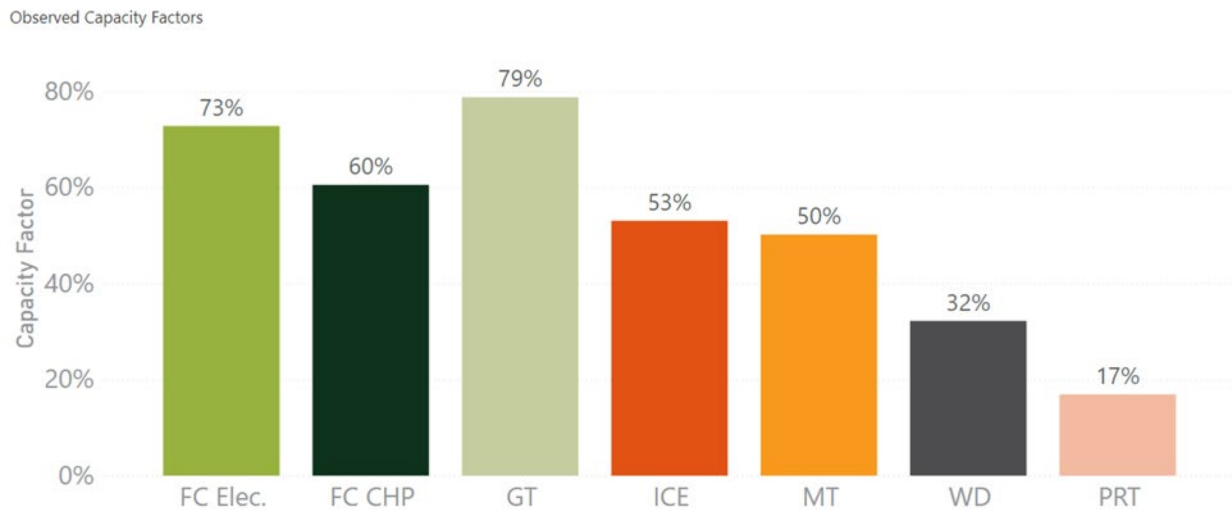
The annual capacity factor of a generation project, CF_a, is defined in Equation 4-2 as the sum of hourly electric net generation output, $ENGO_h$, during all 8,760 hours of the year divided by the product of the project's capacity and 8,760 hours. If a project was completed mid-year, then the annual capacity factor is evaluated from the completion date through the end of the year.

$$CF_a = \frac{\sum ENGO_h[kWh]}{Capacity\ [kW] \times Hours\ of\ Data\ Available\ [hr]}$$

EQUATION 4-2

Figure 4-27 shows the observed average 2023 capacity factors of the program's incentivized generation technologies. Gas turbines and all-electric fuel cells showed the highest capacity factors, followed by CHP fuel cells and microturbines. Other technologies showed much lower capacity factors. Wind turbines are not expected to meet the same capacity factor as other technologies due to the availability of wind in some areas. The expected capacity factor for wind turbines is 25%, whereas the expected capacity factor for baseload technologies is 80%.[32]

FIGURE 4-27: 2023 OBSERVED AVERAGE CAPACITY FACTOR BY GENERATION TECHNOLOGY

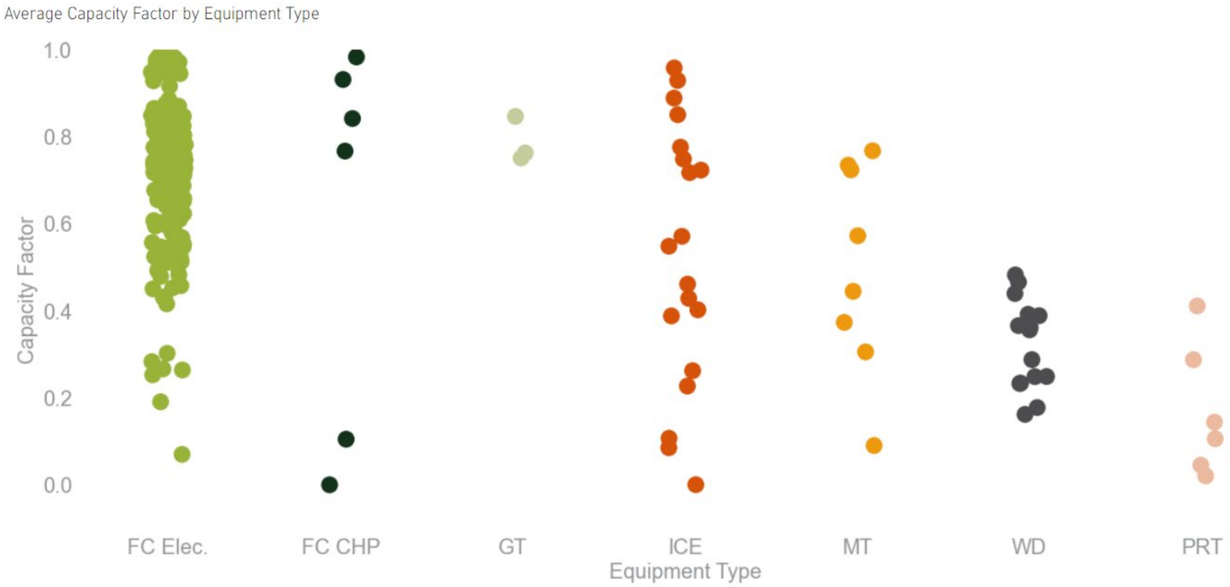


The distribution of project-specific CFs, for those projects that were operational (non-decommissioned)[33], are shown below in Figure 4-28. The few gas turbines all displayed capacity factors that were quite consistent, while all other technologies exhibited substantial site-to-site variation even across their technology. While all-electric fuel cell technologies generally saw higher CFs than other technologies, there was a large spread in the project-specific findings for this equipment.

[32] The SGIP also has a category labeled “dispatchable resource”, for those systems operation intended to firm onsite intermittent renewables, provide peak load shaving, or support flexible loads. The required capacity factor for these systems is 15%, but there are currently no systems incentivized under the SGIP which meet this criteria.

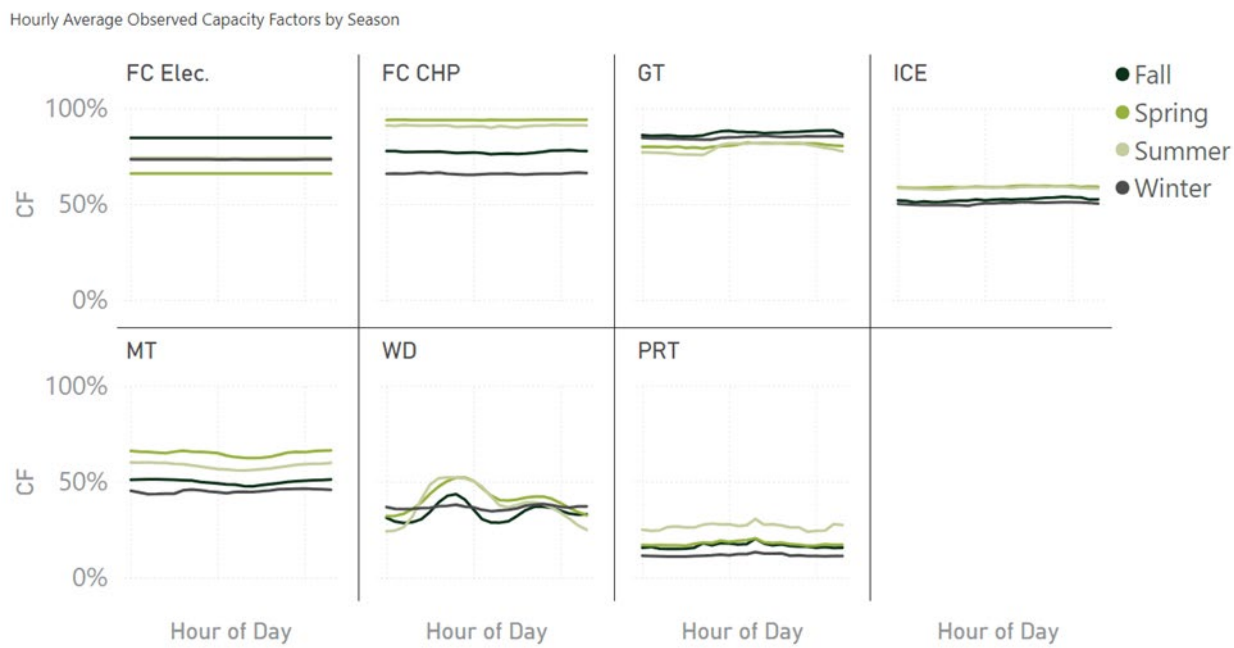
[33] While this does not include decommissioned projects, there were some project that had near-zero generation in 2023 that were not confirmed to be decommissioned.

FIGURE 4-28: DISTRIBUTION OF OBSERVED 2023 CAPACITY FACTORS BY GENERATION TECHNOLOGY



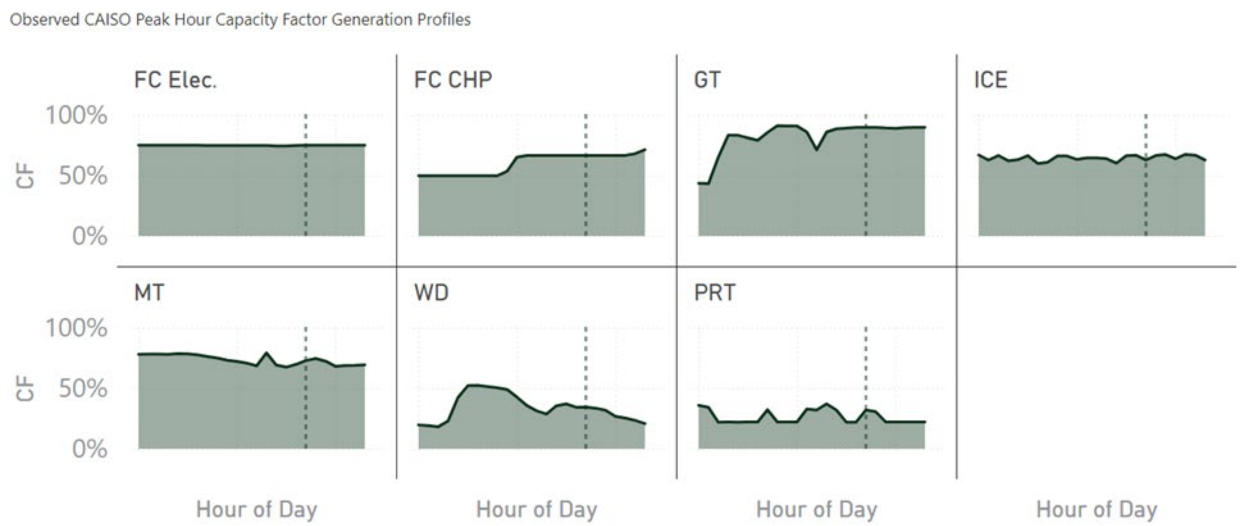
Historically, SGIP generation projects have not been designed to be ramped up and down quickly and are typically intended to satisfy a portion of the facility's base load. As such, except for wind turbines which rely on availability of wind, the capacity factors are typically quite consistent across the day. This is also evident in the program design, which specifies that most generation technologies are to meet an 80% annual capacity factor to realize their full PBI payment. Figure 4-29 presents hourly capacity factor generation profiles across different seasons for non-decommissioned generation systems. The data reiterates the fact that systems are typically designed to handle a facility's base load, and the results do not vary much by season.

FIGURE 4-29: AVERAGE 2023 GENERATION PROFILES BY EQUIPMENT TYPE AND SEASON



Higher utilization coincident with CAISO and IOU peak hours yields greater benefits to the grid than during other hours. The capacity factor generation profiles for each technology during the 2023 CAISO peak day is shown below in Figure 4-30, and the peak hour of the year is also highlighted with the grey dashed line. Across the CAISO peak hour, gas turbines were found to have the highest capacity factors at around 90% (compared to their summer average of about 80%). All-electric fuel cells were found to be around 75% (consistent with their summer average), while CHP fuel cells and microturbines hovered around 70% (compared to their summer averages of 89% and 58%, respectively). As noted previously, generation technologies are generally designed to satisfy facility base load, so there is little variation in their utilization during the peak day or peak hours versus non-peak times. However, no waste heat to power systems were generating in 2023, as the lone system within its permanency period was decommissioned prior to 2021.

FIGURE 4-30: 2023 OBSERVED CAISO PEAK DAY GENERATION PROFILES BY EQUIPMENT TYPE



Electrical, Thermal, and System Efficiency

The ability to convert fuel into useful electrical and thermal energy is measured by the system's combined efficiency in doing both. The combined or overall system efficiency is defined in Equation 4-3 as the ratio of the sum of electrical generation and useful recovered heat[34] to the fuel energy input.

$$C\eta_{system} = \frac{ENGO_{kWh} \times 3.412 + HEAT_{MBtu}}{FUEL_{MBtu,LHV}}$$ **EQUATION 4-3**

The higher the system's overall efficiency the less fuel input is required to produce the sum of electricity and useful recovered heat. Electric-only fuel cells do not require useful heat recovery capabilities; therefore, their system overall efficiency has only an electrical component. Technologies that recover useful heat have electrical and thermal component efficiencies. All efficiencies are reported on a lower heating value (LHV) basis.[35]

34 In the context of this report, useful heat is defined as heat that is recovered from CHP projects and used to serve on-site thermal loads. Waste heat that is lost to the atmosphere or dumped via radiators is not considered useful heat.

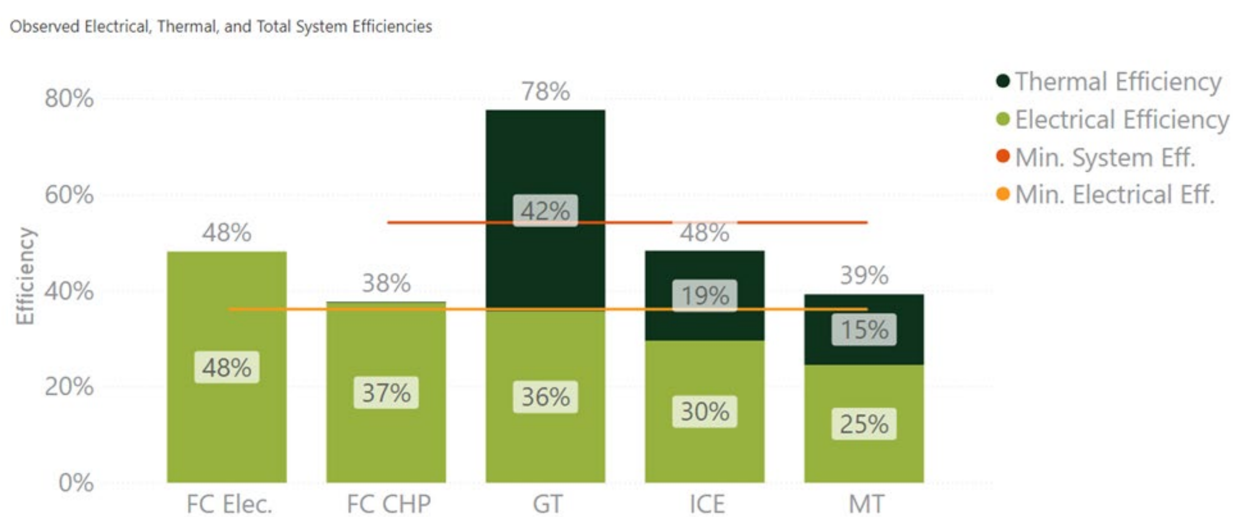
35 This evaluation report assumes a natural gas lower heating value energy content of 934.9 Btu/SCF and higher heating content of 1036.6 Btu/SCF for an LHV/HHV ratio of 0.9019 (Combined Heating, Cooling & Power Handbook: Technologies & Applications. Neil Petchers. The Fairmont Press, 2003.)

The observed overall system and component efficiencies are shown in Figure 4-31. The electrical conversion efficiency is shown in light green while the thermal efficiency in dark green. The figure also displays red and orange horizontal lines, which represent the program minimum system efficiency targets of 54.1% LHV (or 60% HHV) for CHP and 36.1% LHV (40% HHV) for electric-only fuel cells. On average, all-electric fuel cells, and gas turbines met their efficiency targets. CHP fuel cells met their electrical efficiency requirements but not their system efficiency requirements, and internal combustion engines and microturbines, on average, didn't meet either one.

Heat recovery is the most complicated engineering challenge when implementing CHP. If the CHP generator is not appropriately sized to the annual heating and cooling loads of a building, then much of the excess heat must be dumped into the atmosphere through a radiator. Useful heat recovery loops may also be temporarily shut down due to maintenance issues. These types of events can cause this technology to have a low useful heat recovery rate and therefore an observed system efficiency that falls short of design specifications.

In prior evaluations, the heat recovery rates for combustion technologies like internal combustion engines and microturbines saw higher rates of heat recovery. In this evaluation, the thermal efficiencies range between almost 0% up to about 40% for internal combustion engines, and between 2% to 28% for microturbines, resulting in lower overall system efficiencies than have been observed in prior years. CHP fuel cells saw much less heat recovery than in prior years as well.

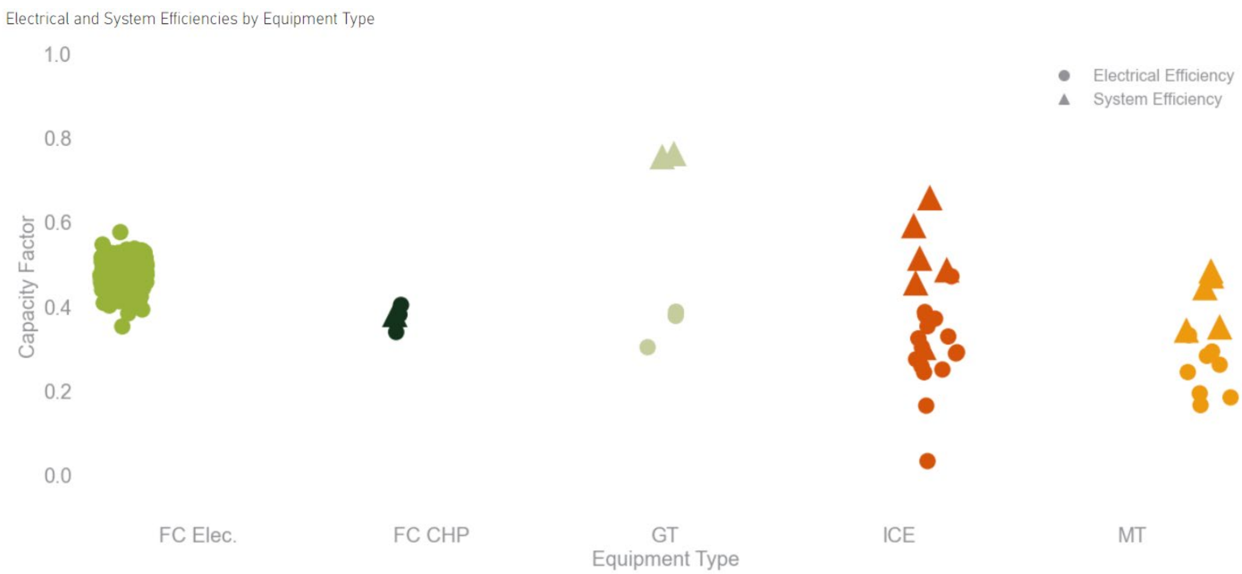
FIGURE 4-31: 2023 OBSERVED WEIGHTED AVERAGE ELECTRICAL, THERMAL, AND SYSTEM EFFICIENCIES BY TECHNOLOGY TYPE



* The total system efficiency displayed above the chart reflects the sum of the average electrical efficiency and the average thermal efficiency. However, it should be noted that the projects that go into a calculated weighted average electrical efficiency

are not always the same projects that go into a calculated weighted average thermal efficiency, due to the availability of metered data, so these overall system efficiencies do not match the system efficincies highlighted below in Figure 4-34.

FIGURE 4-32: DISTRIBUTION OF OBSERVED 2023 ELECTRICAL AND SYSTEM EFFICIENCIES BY GENERATION TECHNOLOGY



Useful Heat Recovery

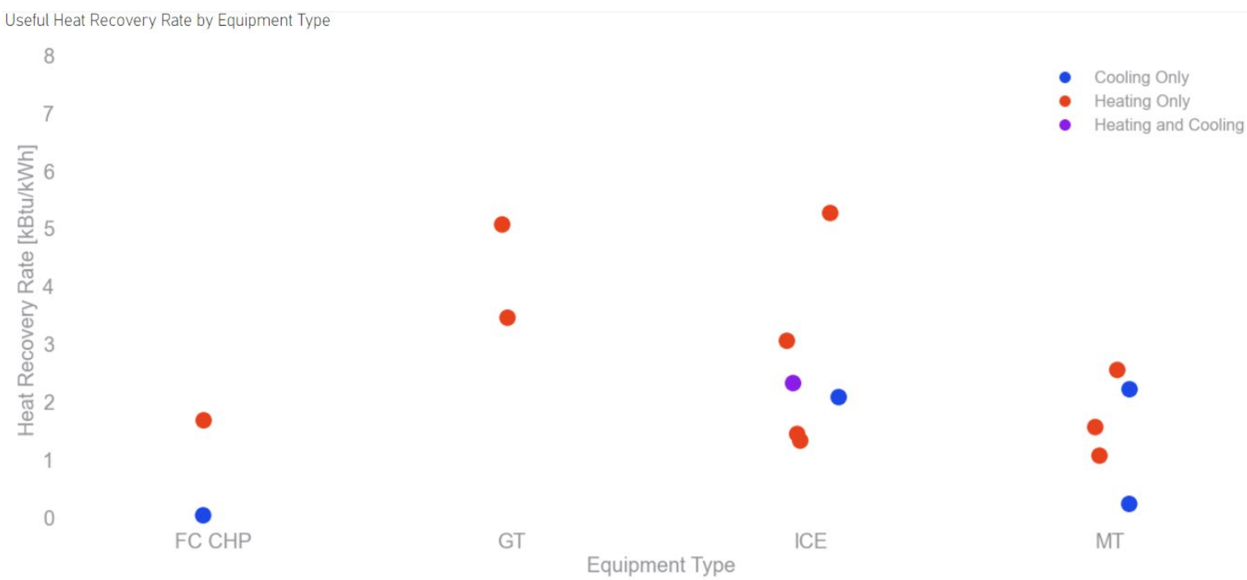
Fuel energy that enters SGIP systems is converted into electricity and heat. Certain SGIP technologies can capture this heat to usefully serve on-site end uses instead of dissipating it to the atmosphere. Except for electric-only fuel cells that achieve high fuel-to-electric conversion efficiencies, the SGIP requires useful heat recovery where natural gas is the predominant fuel. Where the predominant fuel is renewable biogas, the SGIP system is exempt from the heat recovery requirement. The biogas exemption from heat recovery was introduced in the program's first year. The end uses served by heat recovery, heating and cooling have important implications for net greenhouse gas emissions. The comparable baseline measures for heating and cooling are a natural gas boiler and a grid-served electric chiller, respectively. Useful heat recovery that displaces a baseline boiler will reduce emissions more than if it displaces a baseline electric chiller. The distribution of end uses served by useful heat recovery from SGIP systems is summarized in Table 4-2. The incentivized capacity of projects utilizing heat recovery has steadily declined over the last few evaluation cycles. There were 68 projects in 2023 that still recovered heat. This is due in part to projects dropping out of the population due to completing their permanency periods, as well as projects within their permanency period being decommissioned.

TABLE 4-2: END USES SERVED BY USEFUL RECOVERED HEAT

End Use	Project Count	Rated Capacity [MW]	Percent of Rebated Capacity
Cooling Only	7	8	5%
Heating and Cooling	6	12	7%
Heating Only	55	144	88%

Heat recovery rates during 2023 for metered CHP systems are depicted graphically in Figure 4-33. The range of values is large, from 0 to almost 6 kBtu/kWh. However, in general, these rates of heat recovery are lower than was seen in the last 2021-2022 reporting cycle, which has driven the overall average system efficiencies lower this evaluation year. One factor influencing heat recovery rates is electric efficiency. The higher the electrical efficiency, the less energy remains to be captured after generation of electricity. The presence of a thermal load coincident with demand for electricity generation is a second critical factor influencing average heat recovery rates.

FIGURE 4-33: DISTRIBUTION OF OBSERVED 2023 HEAT RECOVERY RATES BY GENERATION TECHNOLOGY AND END USE SERVED



Performance Summaries

Metrics like capacity factors and efficiencies play a key role in determining how generation technologies provide benefits within the SGIP. These performance metrics are generally technology specific. Below we summarize the performance metrics discussed. Also included are observed project counts and total system capacities (in MW), and average system generation (GWh).

FIGURE 4-34: SUMMARY OF 2023 GENERATION PERFORMANCE METRICS BY EQUIPMENT TYPE

2023 Observed Generation Performance Metrics

Equipment Type	Project Count	Rated Capacity [MW]	Electrical Generation [GWh]	Capacity Factor	Electrical Efficiency	System Efficiency
FC Elec.	221	82.96	2.12	73%	48%	
FC CHP	5	4.80	5.12	70%	37%	38%
GT	3	72.84	164.35	79%	36%	76%
ICE	21	24.39	4.41	53%	30%	50%
MT	8	5.53	3.03	50%	25%	42%
WD	17	32.51	3.90	32%		
PRT	6	2.11	0.60	17%		
WHP	0	0.00				
Total	**281**	**225.14**	**4.18**	**67%**	**46%**	**50%**

4.2 CUSTOMER IMPACTS

Customers choosing to participate in the SGIP do so expecting their generation or energy storage system to deliver a variety of impacts to their energy services and bottom lines. Financial impacts are of particular importance to most participants. Electricity tariffs have a temporal dimension: the quantity and timing of use of electricity from the grid influence bills. As such, by operating at certain times, SGIP participants may be able to reduce the billed demand charges and/or the energy charges on their electricity bills. Findings of analysis related to customer impacts are presented below for energy storage and generation technologies.

4.2.1 Energy Storage

Storage systems dispatch objectives are predicated on several different factors including facility and household load profiles, rate structures, other market-based mechanisms, and reliability in the event of an outage. Customers on TOU rates may be incentivized to discharge energy during on-peak hours (when retail energy rates are higher) and avoid charging until off-peak hours when rates are lower. Furthermore, customer rates that assess demand charges during peak demand periods and/or at the monthly billing level may prioritize peak demand reduction. Finally, systems co-located or paired with an on-site generator like solar PV can also exhibit substantially different behavior than a standalone system.

Figure 4-35 demonstrates how residential load shapes are impacted by energy storage system charge and discharge and how those load shapes differ by season[36] and the presence of on-site PV generation. Average customer net load – utility observed delivered and received load – and baseline net load – the delivered and received load the utility would have seen in the absence of storage – are presented along with the season and whether the energy storage system is paired with on-site PV. Also included are vertical light gray lines signifying the 4 pm – 9 pm on-peak period. Furthermore, the vertical axis corresponds to the average hourly baseline and net load normalized by the average capacity of the energy storage system and the horizontal axis corresponds to the hour of the day for each weekday (Monday – Friday). The figure highlights the following:

- The presence of on-site solar is evident in the first two graphics with a drop in load – to export – during late morning and early afternoon hours for both the baseline and net load shapes. This corresponds to excess PV generation being exported back to the grid.

[36] Summer represents June through September inclusive. Winter months are all others.

- The shaded area in yellow represents an increase in customer load relative to a baseline of no storage (battery charging). The green area represents a decrease in customer load (battery discharging).
- PV Paired systems are charging almost exclusively from on-site solar power, so less PV is being exported than in the baseline. Storage system charging, during morning hours, absorbs PV generation that otherwise would have been exported.
- PV Paired systems are discharging almost exclusively on-peak with some discharge occurring thereafter and into the morning hours. Storage discharging replaces grid energy that otherwise would satisfy customer consumption.
- Standalone systems are discharging exclusively during the on-peak and begin charging thereafter, with the greater magnitude of charge occurring after midnight.

FIGURE 4-35: AVERAGE RESIDENTIAL DAILY WEEKDAY LOAD SHAPES (PV PAIRED AND STANDALONE)

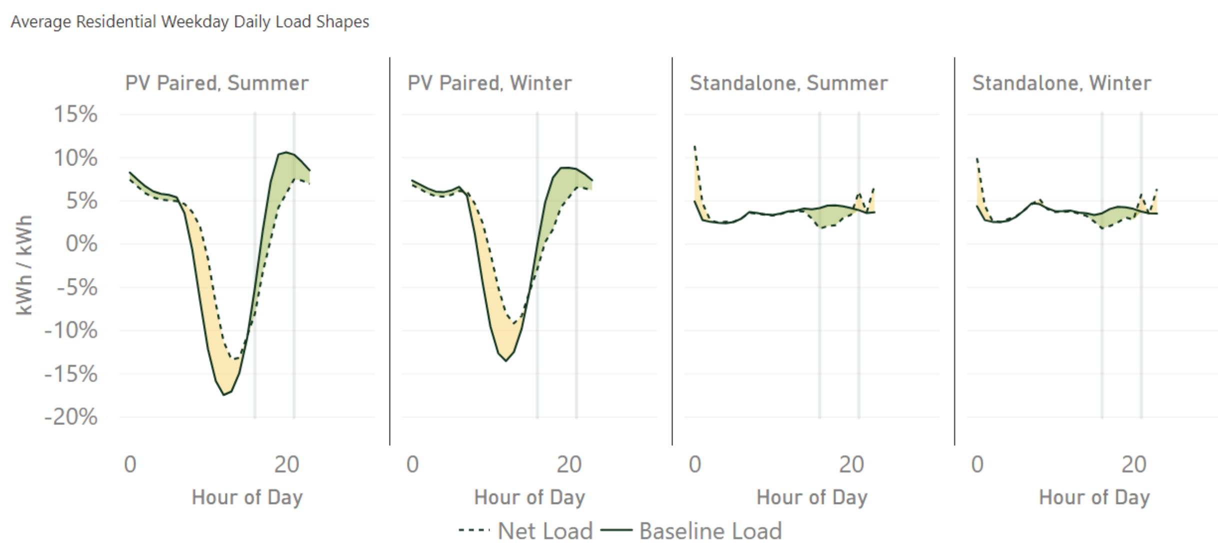
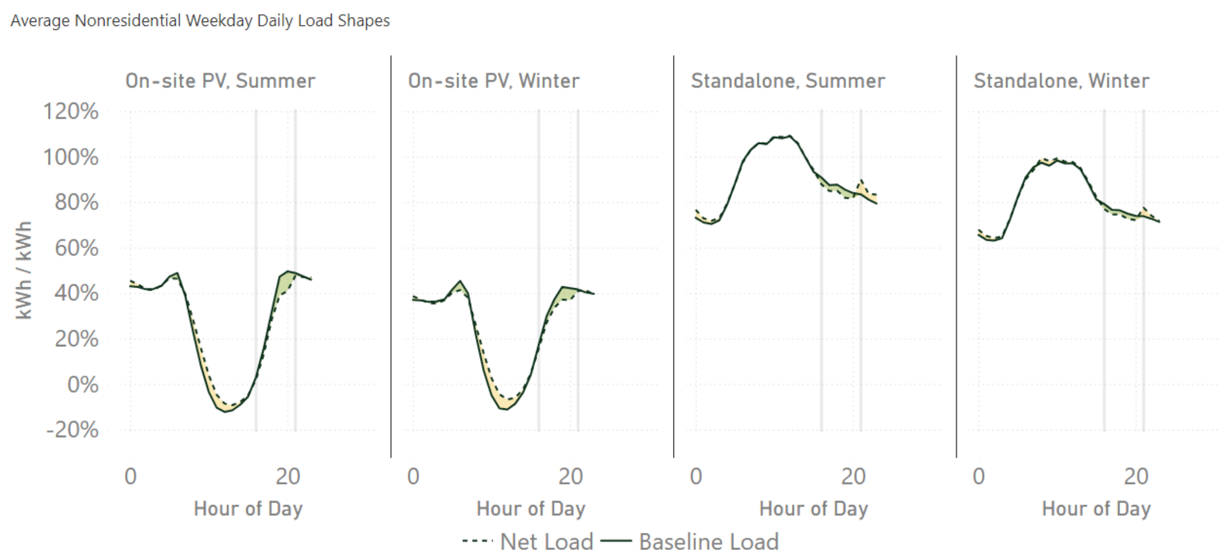


Figure 4-36 demonstrates how nonresidential load shapes are impacted by energy storage system charge and discharge and how those load shapes differ by season and the presence of on-site PV generation. Nonresidential load shapes are far more heterogeneous than residential ones given the variety of facility types, underlying load requirements, and customer bill rate structure. However, some similar patterns can be gleaned from average customer net load – utility observed delivered and received load – and baseline net load – the delivered and received load the utility would have seen in the absence of storage. The 4 pm – 9 pm on-peak period is also highlighted, and average hourly baseline and net load are normalized by the average capacity of the energy storage system for each hour of the weekday. The figure conveys similar information to the residential ones, along with:

- While PV paired systems are charging from on-site solar and discharging on peak, we also observe discharge during early morning hours when consumption ramps prior to PV generation.
- Facilities with standalone systems, on average, are much larger – relative to the size of the storage system – than facilities with on-site solar. Most discharging occurs during the on-peak and charging occurs thereafter. However, systems are also discharging during non-coincident peak hours.

FIGURE 4-36: AVERAGE NONRESIDENTIAL DAILY WEEKDAY LOAD SHAPES (PV PAIRED AND STANDALONE)



While standalone or paired systems may exhibit the same discharge behavior – to satisfy an energy arbitrage opportunity or for self-consumption – solar pairing plays a significant role in dictating when a system charges. Solar PV pairing is a critical source of reduced greenhouse gas emissions and utility avoided costs, because BTM storage charging from on-site solar aligns well with grid-scale renewable production and lower marginal emissions and utility energy costs.

Energy arbitrage opportunities are guided by TOU periods which are based on the electric utility and the customer's rate schedule. During winter and summer months, customers pay a different rate and, within those seasons, pay different rates for each period (on-peak, off-peak and super off-peak[37]). Figure 4-37 demonstrates how residential load shapes are impacted by energy storage system charge and discharge

37 These rate periods are presented across utility definition and naming convention. For this analysis, On-Peak/Off-Peak/Super Off-Peak is equivalent to Peak/Partial-Peak/Off-Peak. The definitions are the same. Rate period naming conventions have been combined for presentation purposes.

and how those load shapes differ by prevalent energy storage operating modes. Average customer net load – utility observed delivered and received load – and baseline net load – the delivered and received load the utility would have seen in the absence of storage – are presented for systems paired with on-site PV. Also included are vertical light gray lines signifying the 4 pm – 9 pm on-peak period. The figure highlights the following:

- **Self-consumption.** This mode represents the majority of residential SGIP dispatch behavior (~64%) and includes discharging during the on-peak period and thereafter until the battery SOC reaches a pre-defined minimum. This mode enables customers to maximize their PV generation and minimize delivered load from the utility. Storage capacity is never exported to the grid under this mode unless a customer participates in a demand response program.
- **TOU Arbitrage**. The middle figure represents the average load shapes for sampled residential customers conducting TOU arbitrage (~30% of sampled projects) and charging their battery from on-site solar. Discharging occurs only during the customer's on-peak period (generally 4 pm – 9 pm) to maximize bill savings opportunities. Some systems regularly discharge excess capacity to the grid, while others only export during demand response events.
- **Under-Utilization/Back-up.** The rightmost figure represents the sample of systems that are idle or under-utilized during the metering period (~6%). Systems here are likely in back-up only mode and maintaining a full SOC in anticipation of an outage or are not being cycled often – both of which don't ascribe to program rules. As a result, baseline and observed net loads are almost identical.

FIGURE 4-37: AVERAGE RESIDENTIAL DAILY WEEKDAY LOAD SHAPES BY OPERATING MODE (PV PAIRED)

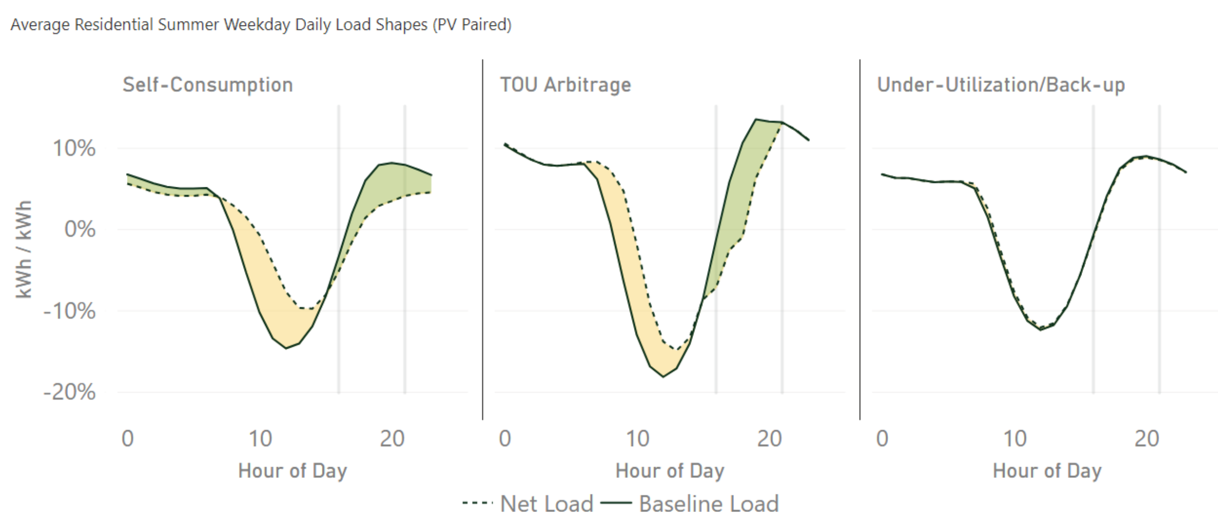
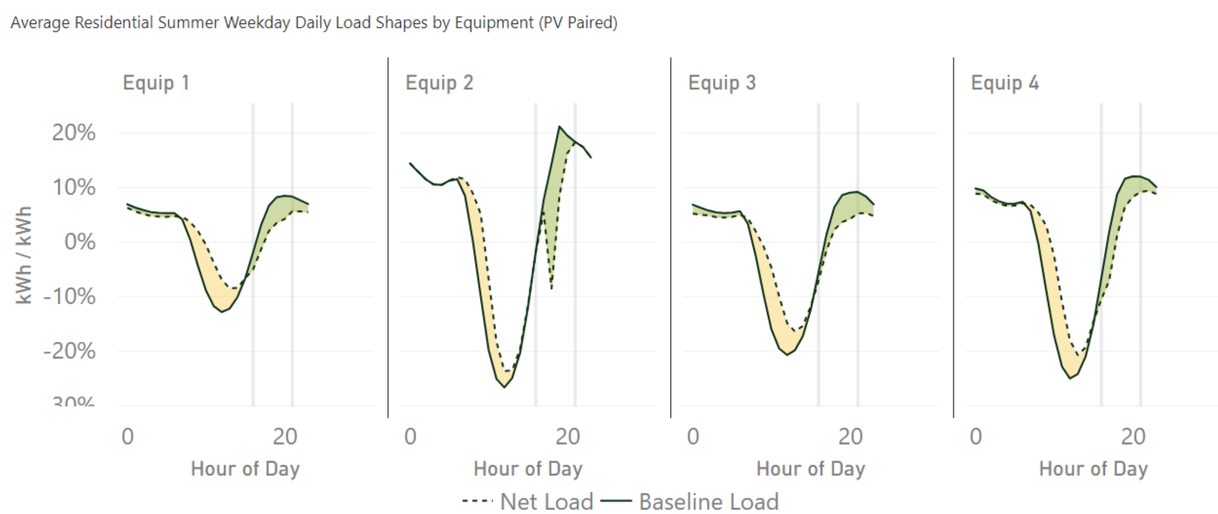


Figure 4-38 presents how baseline and metered summer weekday load shapes differ by equipment manufacturer. This reveals – not surprisingly – that energy storage systems are built with different operating modes and different overall system capacities, are paired with different sized PV systems and service different underlying loads.

FIGURE 4-38: AVERAGE RESIDENTIAL DAILY WEEKDAY LOAD SHAPES BY EQUIPMENT (PV PAIRED)



Some developers not only meter the battery at the inverter, but also meter PV production and customer net load. These metering techniques allow the battery to recognize when net load goes positive or negative and provide an opportunity for a customer to conduct self-consumption. These modes provide differing arbitrage opportunities and discharge patterns based on how the battery is built and how it interacts with customer load and on-site generation. Equipment 2 differs most from the other equipment types in both 1) underlying customer load and 2) discharging exclusively during on-peak hours regularly to export.

Nonresidential storage performance is guided by similar economics, but customer bill rate structure (monthly, on-peak, daily demand charges and TOU energy charges), site-specific power demands and load shapes guide dispatch. Figure 4-39 presents the average baseline and observed metered load for systems paired or co-located with on-site PV by building type. Average load shapes are similar across building type with on-site solar charging prevalent in the morning and early afternoon, and storage discharge occurring during on-peak hours. It’s important to note that, while the load shapes are similar, average demand varies by building type. This is indicated by the different vertical axis scaling for each load shape.

FIGURE 4-39: AVERAGE NONRESIDENTIAL DAILY WEEKDAY LOAD SHAPES BY BUILDING TYPE (ON-SITE PV)

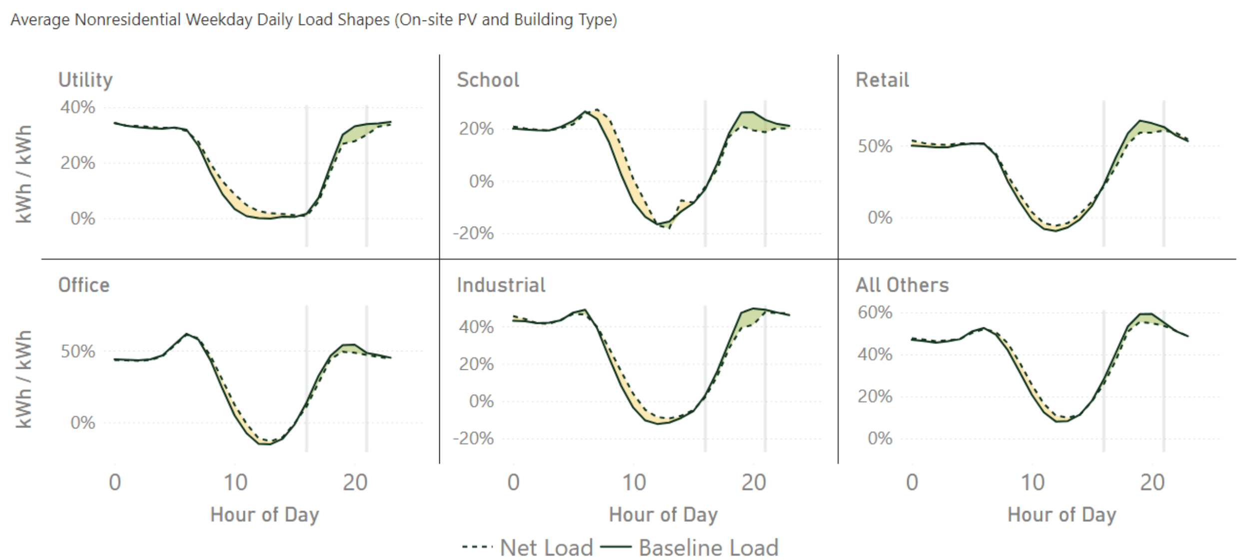
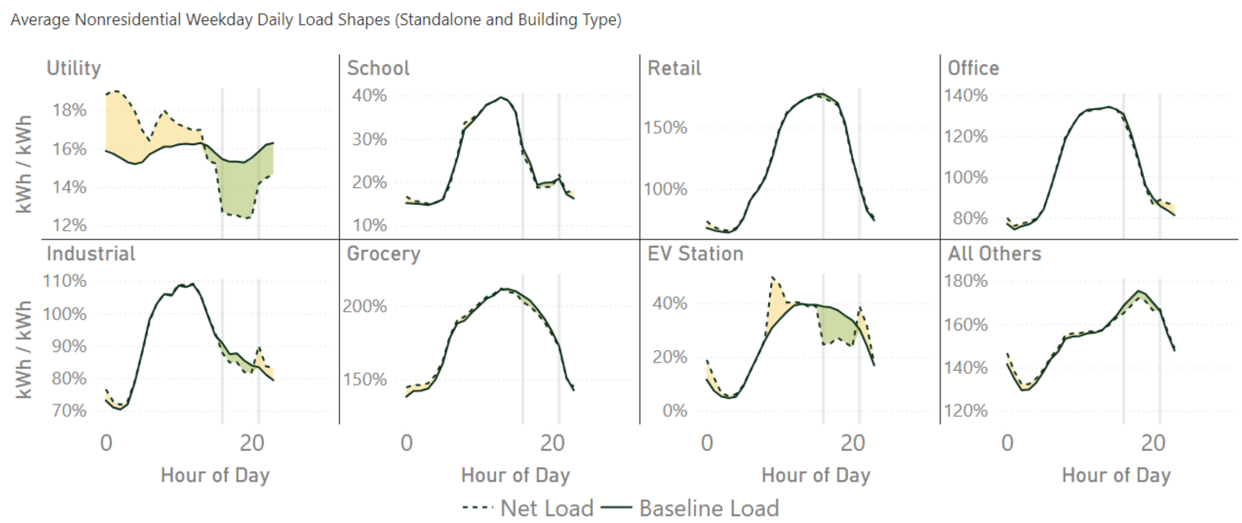


Figure 4-40 highlights the different facility load shapes without on-site PV generation and how storage charge and discharge influence facility load. Without on-site solar generation, variations in the timing and magnitude of average facility peak demand are more prevalent. Retail establishments, on average, tend to have later non-coincident peak periods than schools or industrial facilities. Load shapes for utility (which is comprised mostly of wastewater treatment plants and public works facilities incentivized under the Equity Resiliency Budget (ERB)) are much flatter and less peaky than other building types. These facilities, along with EV charging stations exhibit the most pronounced storage charge and discharge.

FIGURE 4-40: AVERAGE NONRESIDENTIAL DAILY WEEKDAY LOAD SHAPES BY BUILDING TYPE (STANDALONE)



Storage Dispatch Behavior

Verdant analyzed the extent to which customers utilize their storage systems for TOU energy arbitrage, self-consumption, and peak demand reduction. We observed a variety of storage use cases in 2023 which dictate the charge and discharge behaviors during the year. Verdant characterized TOU energy dispatch by quantifying the magnitude of storage discharge by time of day. Retail electricity rates are higher during on-peak hours compared to off-peak and super off-peak hours, so an individual attempting to maximize the energy savings on their bill would be less incentivized to discharge outside on-peak hours. Furthermore, utility marginal costs and grid constraints are generally highest during on-peak hours, with on-peak periods shifting to 4pm – 9pm. Conversely, storage charging is best left to off-peak and super off-peak time periods when retail rates are lower, as are utility avoided costs, marginal emissions, and grid constraints.

Solar PV pairing guides charging during early PV generating hours, and standalone residential systems are charging overnight outside of the on-peak period.

The timing and magnitude of storage charge and discharge is influenced by several factors already discussed: 1) underlying customer load shapes, 2) storage system mode of operation, 3) customer rate schedule, 4) on-site solar PV presence, and 5) storage system sizing relative to customer load. The following bar charts present the average daily weekday percentage of energy discharged and charged during different hours of the day for residential and nonresidential systems. The exhibits also differentiate by season and presence of on-site solar. While a system may discharge exclusively during a billed on-peak period, it may only be discharging a small percentage of total capacity, in which case a customer may not realize bill savings and the potential utilization of the system may go unrealized.

Figure 4-41 presents the magnitude of average daily discharge – as a percentage of energy storage kWh capacity – for the residential sector. Utilization is further broken down by PV paired versus standalone systems, the season, and the time of day of discharge. The figure highlights the following:

- On average, residential systems are discharging roughly 42% of available kWh capacity during summer weekdays. Most of that discharge occurs during the 4pm – 9pm period (9% from 4pm – 6 pm and 16% during 6pm – 9 pm). The remaining capacity is discharged outside the on-peak period – indicating the presence of systems conducting self-consumption in the average.
- On average, standalone systems (~1% of systems) are discharging much less capacity daily (14%) than PV paired systems. Almost all discharge occurs during the 4pm – 9pm hours.
- Utilization for PV paired and standalone systems is less in winter than in summer months. Summer months carry higher on-peak price differentials than winter months, making energy arbitrage less attractive. Customers also generally have lower electric demand during winter months, so less energy capacity is required to meet household consumption.

FIGURE 4-41: RESIDENTIAL DAILY DISCHARGE KWH PER CAPACITY KWH BY TIME OF DAY

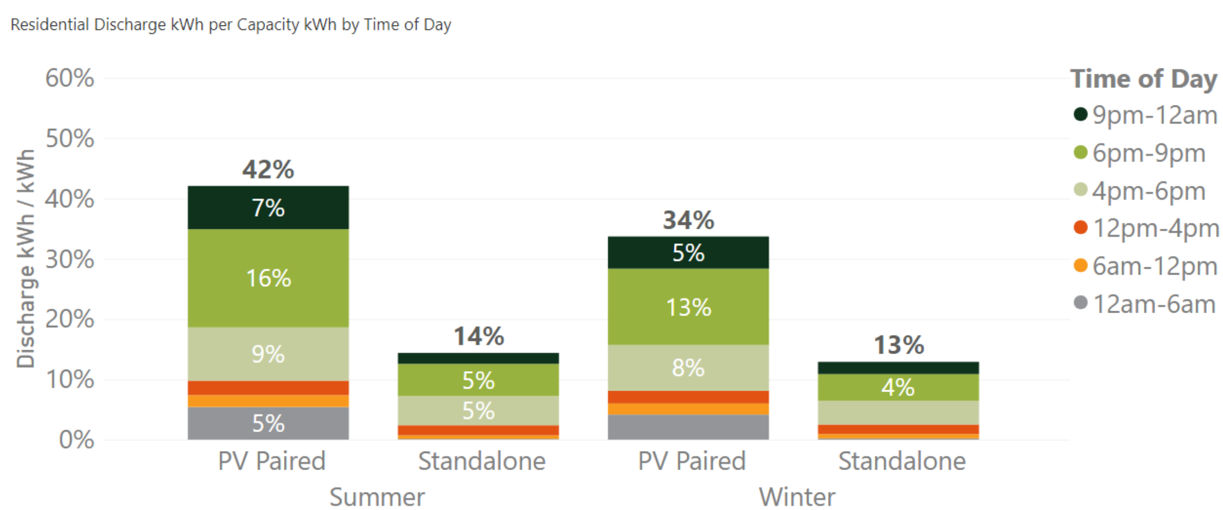


Figure 4-42 presents the magnitude of average daily discharge in the nonresidential sector. We observe similar utilization during summer months to the residential sector, with 46% of available capacity discharged daily. Standalone systems exhibit greater utilization than the residential sector, and overall winter utilization is greater. More discharge occurs during the 4pm – 9pm on-peak.

FIGURE 4-42: NONRESIDENTIAL DAILY DISCHARGE KWH PER CAPACITY KWH BY TIME OF DAY

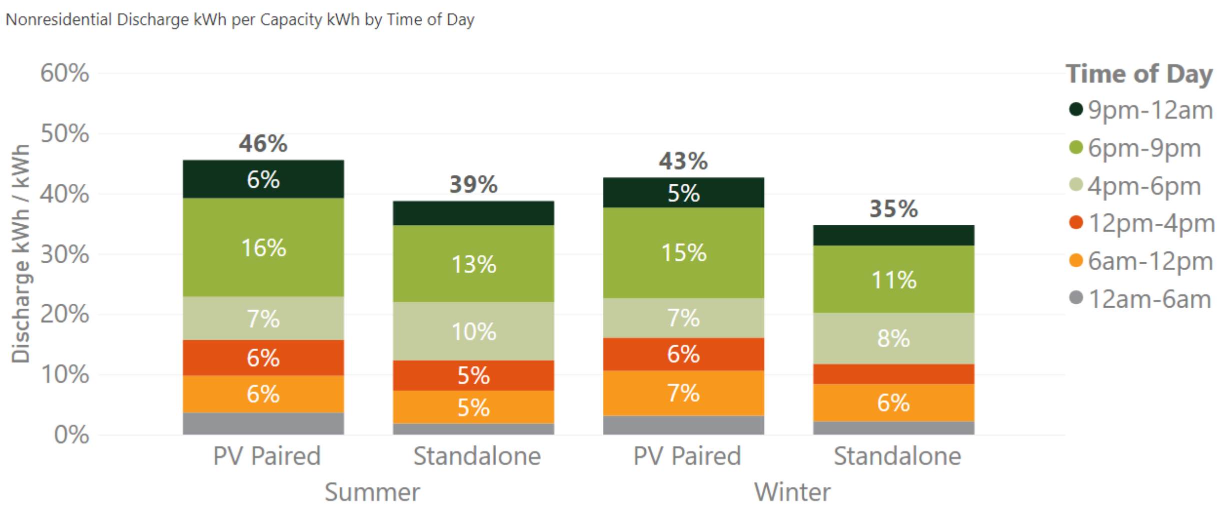


Figure 4-43 and Figure 4-44 present average daily charging magnitudes in the residential and nonresidential sectors, respectively. We observe PV paired systems charging almost exclusively during 6am – 4pm when on-site PV is generating. Standalone residential systems charge exclusively after 9pm and through the midnight hours.

FIGURE 4-43: RESIDENTIAL DAILY CHARGE KWH PER CAPACITY KWH BY TIME OF DAY

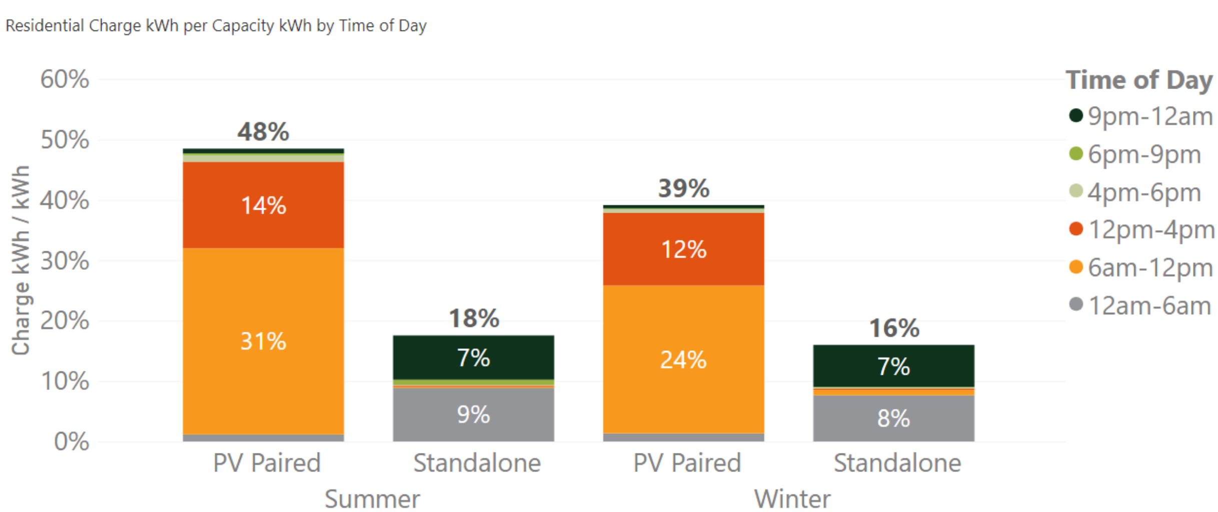
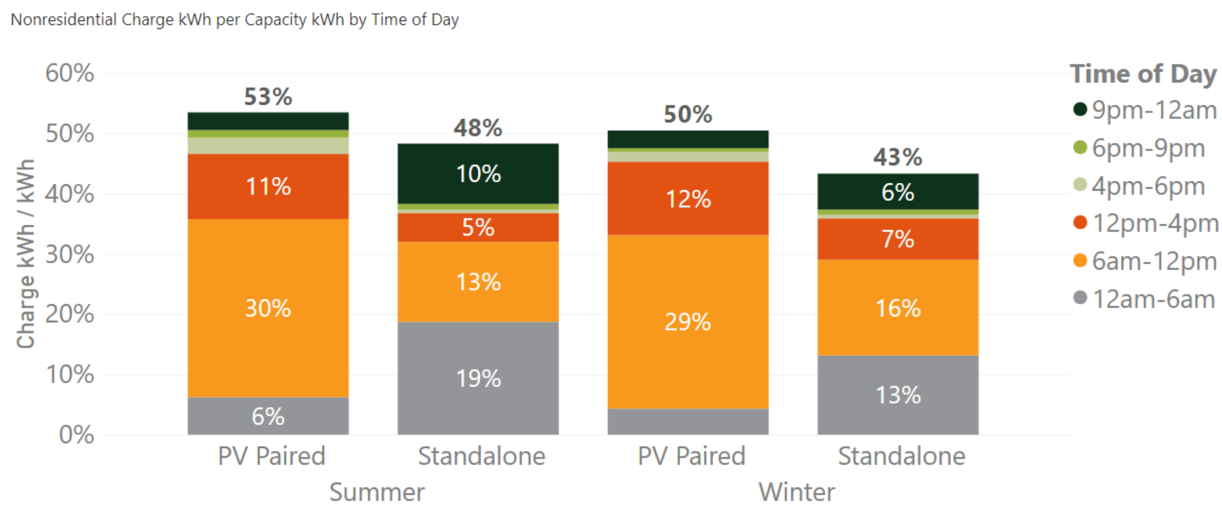
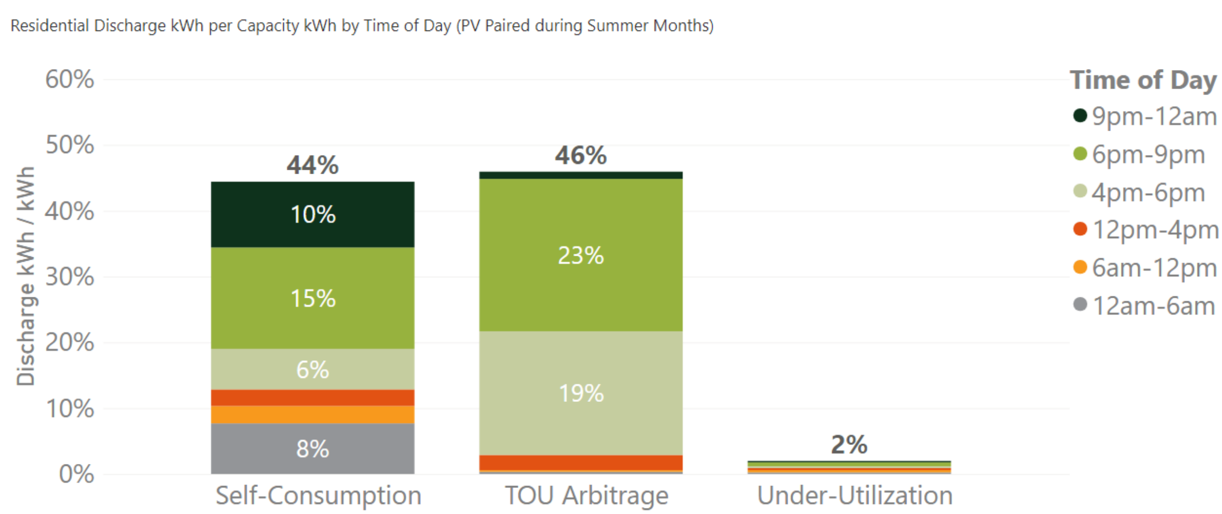


FIGURE 4-44: NONRESIDENTIAL DAILY CHARGE KWH PER CAPACITY KWH BY TIME OF DAY



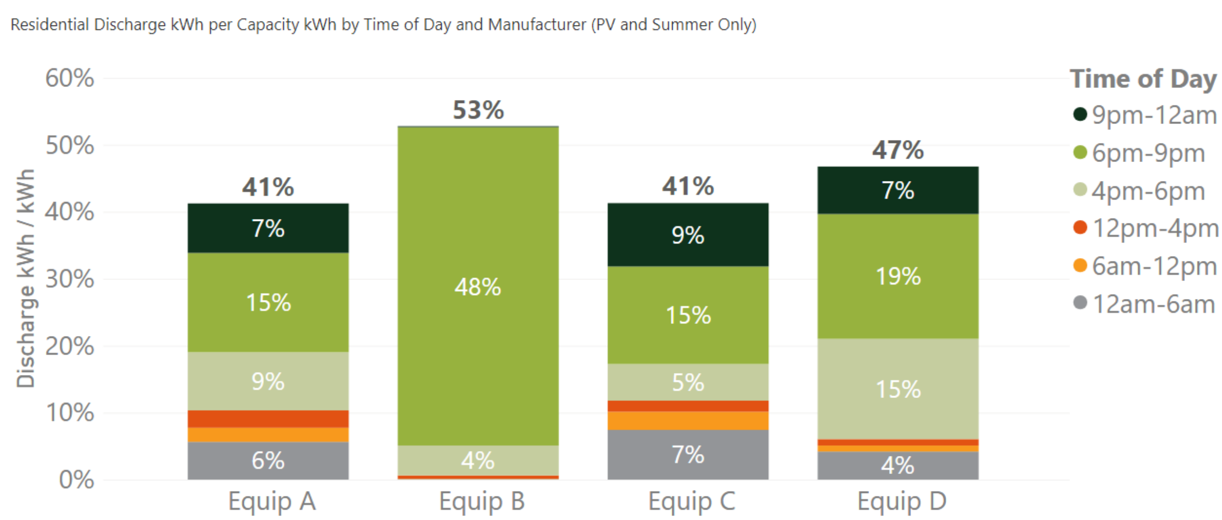
As presented above in Figure 4-37, average daily residential load shapes can differ substantially from baseline to retrofit based on the dispatch patterns and operating modes of the energy storage system. This is evident below in Figure 4-45 where we summarize utilization by time of day for each of three prevalent residential operating modes. As expected, systems operating in self-consumption limit imported load by discharging the battery, even outside of on-peak hours. TOU arbitrage aims to maximize bill savings, so discharge is reserved for on-peak billed periods only. However, there is little difference in the overall daily utilization.

FIGURE 4-45: DAILY DISCHARGE KWH PER CAPACITY KWH BY TIME OF DAY AND OPERATING MODE



Likewise, patterns and magnitudes of discharge vary based on equipment manufacturer. Figure 4-46 presents the average discharge as a percentage of kWh capacity for the four main system types evaluated in this study. Average storage utilization is provided for PV paired systems operating in summer months of 2023 and range from 41% of kWh capacity to 53%. Overall average utilization of Equipment A, C, and D differ slightly, but discharge utilization outside of on-peak hours provide further evidence that TOU arbitrage and self-consumption are both being exercised across system fleets. Equipment B is the only one discharging exclusively for TOU arbitrage, with almost all discharge coming during the 6pm – 7pm period (48% of total system kWh capacity).

FIGURE 4-46: DAILY DISCHARGE KWH PER CAPACITY KWH BY TIME OF DAY AND EQUIPMENT TYPE



Average daily discharge magnitudes for nonresidential systems by building type and presence of on-site PV generation are also presented below in Figure 4-47 and Figure 4-48. Industrial facilities and schools with on-site PV are utilized more during summer weekdays than other facility types. While energy storage systems installed in public utility facilities like wastewater treatment plants via the ERB category are generally longer duration systems, they are only utilizing roughly 33% of available capacity during summer weekdays. Discharging outside the on-peak periods represent either 1) systems conducting self-consumption, 2) systems conducting non-coincident demand charge reduction, 3) systems arbitraging or conducting demand charge reduction on an older rate without a 4pm – 9pm on-peak or 4) systems discharging a minimum capacity until a minimum SOC is reached or on-site PV begins generating.

Standalone systems installed at EV charging stations exhibit the greatest utilization during summer weekdays as well as the most focused discharge on-peak. Again, longer duration systems installed at public utility facilities exhibit lower utilization rates. However, standalone systems at schools and offices exhibit the lowest utilization rates across building types.

FIGURE 4-47: DAILY DISCHARGE KWH PER CAPACITY KWH BY TIME OF DAY AND BUILDING TYPE (PV PAIRED)

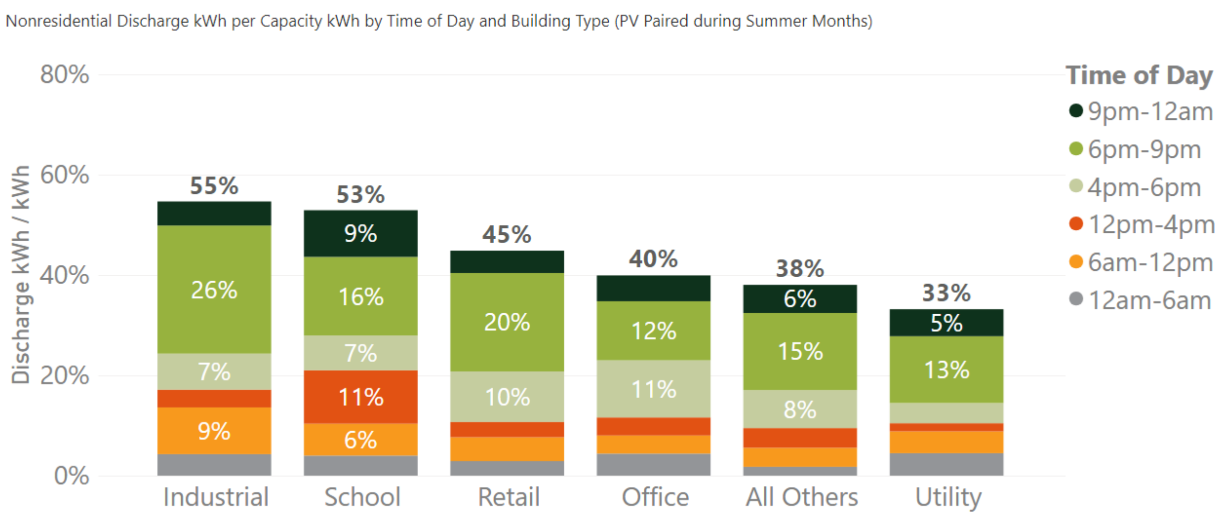
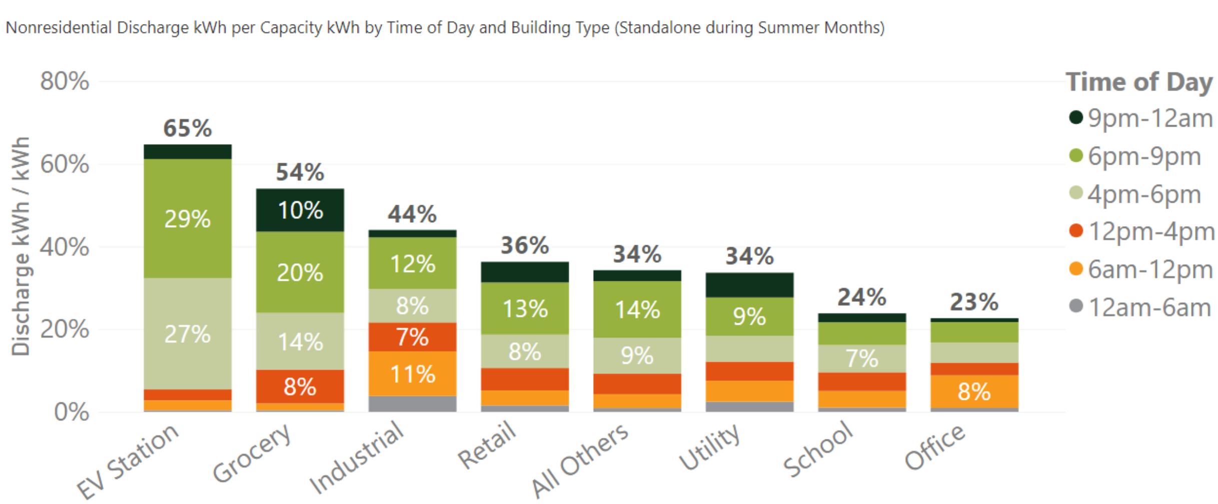


FIGURE 4-48: DAILY DISCHARGE KWH PER CAPACITY KWH BY TIME OF DAY AND BUILDING TYPE (STANDALONE)



Residential storage systems and nonresidential systems utilize less storage capacity, on average, daily than available. The following discussion reveals the more granular timing of dispatch behavior to further understand how storage systems are being utilized throughout the year. This was conducted by developing the average hourly charge and discharge kWh as a percentage of system kWh capacity for each month and weekday hour. These summaries are further separated into percentage of discharge (+) and charge (-) only and whether a storage system is paired with on-site PV or not. Times represent weekdays only (Monday-Friday) and are all presented as hour beginning and in Pacific Local Time. Furthermore, months are displayed on the vertical axis and the hour of the day is exhibited across the top horizontal axis. Finally, the heatmap color gradient goes from dark green – signifying the hours of greatest utilization – to red – which captures the greatest magnitude of system charging.

Figure 4-49 through Figure 4-51 present these results for residential systems; 1) paired with on-site PV and charging from on-site solar (97% of solar paired systems), 2) paired with on-site PV, but charging from grid energy (3%), and 3) standalone (1% of overall sample). As is evident above in the daily summaries, the greatest magnitude of discharge, on average, occurs during the 4 pm to 9 pm hours (16 through 20 in the exhibit below). The magnitude of discharge drops off thereafter, but the pattern of less and less energy being discharged as customers transition to off-peak and super off-peak periods is evident in the data. Residential storage systems paired with PV are almost exclusively charging during early to mid-morning hours, which coincides with early PV generation hours, and charging generally tails off after 12 noon when the battery is sufficiently full. Charging behavior for standalone systems and PV paired systems charging from grid energy are similar in that both groups begin charging after the 9pm hour, with the greatest magnitude of charging beginning at midnight.

Verdant has observed more systems choosing to forego charging from solar (~3%) than previous evaluation years. Most of these customers are enrolled in an electric vehicle rate which charges customers much lower energy prices during super off-peak hours to encourage EV charging during these times. Customers on the EV2-A in PG&E service territory, for example, pay 50% less per kWh during the super off-peaks hours of 12 am – 3pm. It's unclear why the battery would forego charging from solar if the customer is paying the same $/kWh at midnight as they would at 10 am when on-site solar is generating. Whatever the reason, this behavior impacts greenhouse gas emissions – something that is discussed in further detail in Section 4.4.

FIGURE 4-49: RESIDENTIAL HOURLY NET CHARGE (KWH) / CAPACITY (KWH) STANDALONE SYSTEMS

Average Hourly Residential Standalone Net Discharge kWh / kWh Capacity

BY MONTH, HOUR

Month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
January	-5%	-3%	-0%	0%	-0%	-0%	-0%	0%	-1%	0%	0%	0%	0%	0%	0%	1%	2%	2%	2%	1%	1%	-2%	0%	-3%
February	-5%	-3%	-0%	0%	-0%	-0%	0%	0%	-0%	0%	0%	0%	0%	0%	0%	1%	2%	2%	2%	1%	1%	-2%	0%	-3%
March	-5%	-1%	-0%	0%	-0%	-0%	0%	0%	-1%	0%	0%	0%	0%	0%	1%	1%	1%	2%	1%	1%	1%	-2%	0%	-3%
April	-5%	-1%	-0%	0%	-0%	-0%	-0%	0%	-0%	0%	0%	0%	0%	0%	0%	1%	2%	2%	2%	1%	1%	-2%	0%	-3%
May	-5%	-2%	0%	0%	-0%	-0%	-0%	0%	-0%	0%	0%	0%	0%	0%	0%	1%	2%	2%	2%	1%	1%	-2%	0%	-3%
June	-6%	-3%	-0%	-0%	-0%	-0%	-0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	2%	2%	2%	1%	-2%	0%	-3%
July	-6%	-3%	-0%	-0%	-0%	-0%	-0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	3%	3%	3%	2%	0%	-3%	-0%	-3%
August	-6%	-3%	-0%	0%	-0%	-0%	-0%	-0%	0%	0%	0%	0%	0%	0%	0%	1%	3%	2%	2%	2%	1%	-3%	-0%	-3%
September	-5%	-2%	0%	-0%	-0%	-0%	-0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	2%	2%	1%	1%	-2%	0%	-3%
October	-5%	-2%	-0%	0%	-0%	-0%	-0%	0%	-1%	0%	0%	0%	0%	0%	0%	1%	2%	2%	2%	2%	1%	-2%	0%	-3%
November	-5%	-2%	-0%	-0%	-0%	-0%	-0%	0%	-1%	0%	0%	0%	0%	0%	0%	1%	2%	2%	2%	2%	1%	-2%	0%	-3%
December	-6%	-2%	-0%	-0%	-0%	-0%	-0%	0%	-1%	0%	0%	0%	0%	0%	0%	1%	2%	2%	2%	2%	1%	-2%	0%	-3%

FIGURE 4-50: RESIDENTIAL HOURLY NET CHARGE (KWH) / CAPACITY (KWH) PV PAIRED CHARGING FROM GRID

Average Hourly Residential PV Paired Net Discharge kWh / kWh Capacity (Charging from Grid)
BY MONTH, HOUR

Month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
January	-6%	-5%	-3%	-1%	-0%	-0%	0%	-0%	-2%	-2%	-2%	-2%	-1%	-1%	0%	2%	6%	7%	6%	4%	4%	-2%	-1%	-2%
February	-7%	-5%	-2%	-1%	-0%	-0%	0%	-0%	-2%	-3%	-3%	-2%	-2%	-1%	0%	1%	5%	7%	6%	4%	4%	-1%	-1%	-2%
March	-9%	-5%	-2%	-1%	-0%	-0%	1%	1%	-2%	-2%	-3%	-2%	-2%	-1%	-0%	1%	5%	6%	5%	4%	4%	-1%	0%	-1%
April	-13%	-6%	-1%	-0%	-0%	-0%	1%	0%	-2%	-2%	-2%	-2%	-2%	-1%	0%	1%	5%	6%	6%	5%	4%	-1%	1%	-2%
May	-13%	-5%	-1%	-0%	-0%	-0%	0%	-0%	-2%	-2%	-1%	-2%	-1%	-1%	0%	2%	5%	6%	6%	5%	5%	-3%	-0%	-3%
June	-13%	-6%	-1%	-0%	-0%	-0%	-0%	-0%	-0%	-1%	-1%	-1%	-1%	-0%	0%	2%	5%	6%	6%	5%	5%	-5%	-1%	-4%
July	-14%	-8%	-2%	-1%	-0%	-0%	-0%	-0%	-0%	-0%	-1%	-1%	-1%	-0%	1%	2%	8%	10%	9%	6%	4%	-8%	-5%	-4%
August	-13%	-7%	-1%	-1%	-0%	-0%	-0%	-0%	-0%	-0%	-1%	-0%	-0%	-0%	1%	2%	7%	9%	8%	5%	3%	-7%	-4%	-4%
September	-14%	-7%	-1%	-1%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	1%	2%	7%	8%	7%	5%	3%	-7%	-3%	-4%
October	-14%	-6%	-1%	-1%	-0%	-0%	-0%	-0%	-2%	-1%	-0%	-0%	0%	0%	1%	2%	7%	8%	6%	5%	3%	-4%	-2%	-4%
November	-13%	-6%	-1%	-1%	-0%	-0%	-0%	-0%	-2%	-1%	-0%	-0%	-0%	0%	1%	2%	6%	7%	6%	4%	3%	-3%	-1%	-3%
December	-13%	-7%	-1%	-0%	-0%	-0%	-0%	-0%	-2%	-2%	-1%	-0%	-0%	0%	1%	2%	6%	7%	6%	4%	3%	-3%	-1%	-3%

FIGURE 4-51: RESIDENTIAL HOURLY NET CHARGE (KWH) / CAPACITY (KWH) PV PAIRED CHARGING FROM PV

Average Hourly Residential PV Paired Net Discharge kWh / kWh Capacity (Charging from Solar)
BY MONTH, HOUR

Month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
January	0%	0%	0%	0%	0%	0%	0%	-0%	-2%	-4%	-6%	-6%	-5%	-3%	-1%	0%	3%	4%	5%	3%	2%	1%	1%	1%
February	1%	1%	1%	0%	0%	0%	0%	-0%	-3%	-6%	-8%	-7%	-5%	-3%	-2%	-0%	3%	5%	6%	4%	3%	2%	2%	1%
March	1%	1%	1%	0%	0%	0%	0%	-0%	-3%	-5%	-7%	-6%	-5%	-3%	-2%	-1%	2%	3%	5%	4%	3%	2%	2%	1%
April	1%	1%	1%	1%	1%	1%	1%	-0%	-4%	-7%	-9%	-8%	-5%	-3%	-1%	-0%	2%	3%	4%	4%	4%	3%	2%	2%
May	1%	1%	1%	1%	1%	1%	1%	-1%	-3%	-6%	-8%	-7%	-5%	-4%	-2%	-1%	1%	3%	4%	4%	4%	3%	2%	2%
June	2%	1%	1%	1%	1%	1%	1%	-1%	-4%	-7%	-8%	-8%	-6%	-4%	-2%	-0%	2%	3%	5%	4%	4%	3%	3%	2%
July	1%	1%	1%	1%	1%	1%	0%	-1%	-5%	-8%	-10%	-9%	-6%	-3%	-1%	0%	4%	5%	6%	6%	5%	3%	2%	2%
August	1%	1%	1%	1%	1%	1%	0%	-1%	-4%	-8%	-10%	-9%	-7%	-4%	-2%	-0%	3%	5%	6%	6%	5%	3%	2%	2%
September	1%	1%	1%	1%	1%	1%	1%	-0%	-3%	-6%	-9%	-9%	-7%	-4%	-2%	-0%	3%	5%	6%	6%	5%	3%	2%	2%
October	1%	1%	1%	1%	1%	1%	1%	0%	-2%	-6%	-9%	-9%	-7%	-4%	-2%	-0%	3%	5%	6%	6%	4%	3%	2%	1%
November	1%	0%	0%	0%	0%	0%	0%	-1%	-3%	-6%	-8%	-7%	-5%	-3%	-1%	1%	4%	5%	5%	4%	3%	2%	1%	1%
December	0%	0%	0%	0%	0%	0%	0%	-0%	-2%	-5%	-6%	-6%	-5%	-3%	-1%	1%	4%	5%	5%	3%	2%	1%	1%	1%

Figure 4-52 and Figure 4-53 summarize the hourly discharge and charge of standalone nonresidential systems and those paired with or co-located with on-site PV, respectively. Darker green coloring within the 4pm – 9pm period suggests TOU arbitrage as a prominent use case. Facilities with peak loads coincident to on-peak, customers on rates with on-peak daily demand charges, and systems following the GHG signal may also prioritize discharge during these hours. Standalone systems begin charging after 9pm local time and continue throughout the evening. Again, these hourly net discharge values represent a variety of different facility types, energy storage capacities, underlying facility loads, and rate structures.

With on-site solar, monthly non-coincident peaks might occur during non-generating hours. Also, solar generation may not always meet or exceed customer BTM consumption, so the battery may be dispatched to make up the difference. The first point is evident during 6am – 7am. We observe nonresidential discharge during early morning facility load ramps, but prior to PV generation. The second point is evident during 12pm – 2pm with reduced net charging. Facility load may exceed on-site generation during those hours, so the battery is discharged to make up the difference. Charging occurs mostly during early PV generating hours with some charging in the early afternoon and overnight, potentially to fill up after a demand-related discharge.

FIGURE 4-52: NONRESIDENTIAL HOURLY NET CHARGE (KWH) / CAPACITY (KWH) STANDALONE

Average Nonresidential Standalone Net Discharge kWh / kWh Capacity

BY MONTH, HOUR

Month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
January	-3%	-2%	-2%	-1%	-1%	-0%	1%	1%	-2%	-3%	-3%	-3%	-2%	-1%	-1%	-1%	3%	5%	4%	3%	3%	-1%	-1%	-1%
February	-3%	-2%	-2%	-1%	-1%	-0%	1%	1%	-3%	-4%	-3%	-2%	-1%	-1%	-1%	-1%	3%	4%	4%	3%	3%	-1%	-1%	-1%
March	-3%	-2%	-2%	-1%	-1%	-0%	1%	1%	-2%	-4%	-4%	-3%	-2%	-1%	-1%	-1%	3%	4%	4%	4%	4%	-0%	-1%	-0%
April	-3%	-2%	-2%	-1%	-1%	0%	1%	0%	-3%	-5%	-4%	-2%	-2%	-1%	-1%	-1%	3%	3%	3%	4%	4%	-0%	-1%	-1%
May	-3%	-2%	-2%	-2%	-1%	-0%	0%	-0%	-3%	-5%	-3%	-2%	-1%	-1%	-1%	-0%	3%	3%	3%	4%	4%	-1%	-1%	-1%
June	-4%	-3%	-3%	-2%	-1%	-1%	-0%	-1%	-1%	-3%	-3%	-1%	-1%	-0%	-0%	-0%	4%	4%	4%	4%	5%	-2%	-2%	-1%
July	-4%	-3%	-3%	-2%	-2%	-1%	-0%	-2%	-2%	-4%	-3%	-1%	-0%	0%	0%	0%	4%	4%	4%	5%	5%	-2%	-2%	-2%
August	-4%	-3%	-3%	-3%	-2%	-1%	-0%	-1%	-2%	-3%	-3%	-1%	-1%	-0%	0%	0%	4%	4%	4%	4%	4%	-2%	-2%	-1%
September	-4%	-3%	-3%	-2%	-2%	-1%	0%	-0%	-2%	-4%	-3%	-2%	-1%	-1%	0%	0%	4%	4%	4%	4%	4%	-2%	-1%	-0%
October	-3%	-2%	-2%	-2%	-1%	-0%	1%	1%	-3%	-5%	-4%	-2%	-1%	-1%	-1%	-1%	4%	4%	4%	4%	4%	-1%	-1%	-0%
November	-3%	-2%	-2%	-1%	-1%	-0%	1%	0%	-3%	-5%	-4%	-2%	-1%	-1%	-1%	-0%	4%	4%	4%	4%	4%	-1%	-1%	0%
December	-3%	-2%	-2%	-1%	-1%	-0%	1%	1%	-3%	-5%	-4%	-2%	-1%	-1%	-1%	-0%	4%	4%	4%	4%	4%	-1%	-0%	0%

FIGURE 4-53: NONRESIDENTIAL HOURLY NET CHARGE (KWH) / CAPACITY (KWH) WITH ON-SITE PV

Average Nonresidential with On-site PV Net Discharge kWh / kWh Capacity

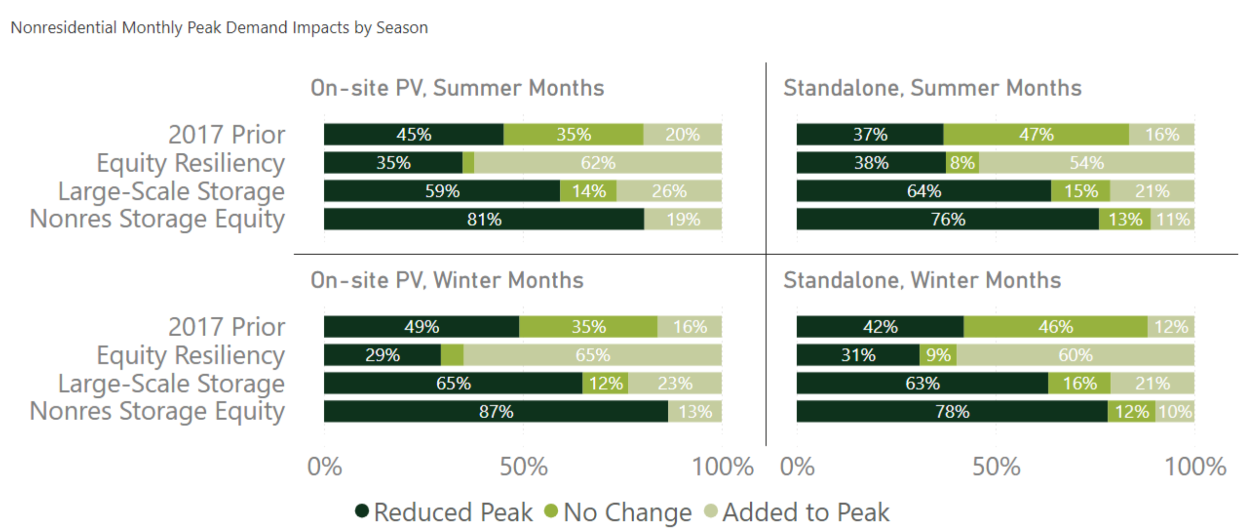
BY MONTH, HOUR

Month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
January	-1%	-1%	-0%	0%	-0%	0%	2%	1%	-3%	-6%	-7%	-6%	-3%	-1%	-2%	-0%	2%	4%	4%	5%	4%	1%	-0%	0%
February	-1%	-1%	-0%	0%	-0%	1%	3%	1%	-4%	-7%	-8%	-6%	-3%	-1%	-2%	-0%	2%	4%	5%	5%	5%	1%	-0%	0%
March	-1%	-1%	-0%	0%	0%	1%	2%	1%	-3%	-6%	-7%	-6%	-3%	-2%	-3%	-1%	0%	2%	4%	5%	5%	2%	0%	1%
April	-1%	-0%	-0%	0%	0%	1%	3%	0%	-4%	-7%	-8%	-6%	-3%	-2%	-3%	-1%	-0%	2%	3%	6%	6%	3%	1%	1%
May	-1%	-1%	-0%	-0%	-0%	1%	2%	-1%	-4%	-6%	-6%	-5%	-3%	-2%	-3%	-1%	-0%	2%	3%	6%	6%	2%	1%	1%
June	-1%	-1%	-0%	-0%	0%	1%	1%	-2%	-5%	-6%	-6%	-5%	-2%	-1%	-3%	-0%	1%	3%	3%	5%	7%	3%	1%	1%
July	-1%	-1%	-1%	-0%	-0%	1%	1%	-2%	-6%	-8%	-6%	-4%	-2%	-1%	-2%	-0%	1%	3%	3%	6%	7%	3%	1%	0%
August	-1%	-1%	-1%	-0%	-0%	0%	1%	-2%	-5%	-7%	-6%	-5%	-2%	-1%	-1%	-0%	1%	3%	3%	6%	6%	2%	1%	-0%
September	-2%	-1%	-1%	-0%	-0%	0%	1%	-0%	-4%	-6%	-6%	-5%	-3%	-1%	-1%	0%	1%	4%	4%	6%	6%	2%	0%	-0%
October	-1%	-1%	-0%	-0%	-0%	0%	2%	1%	-4%	-7%	-7%	-6%	-3%	-1%	-2%	-0%	2%	4%	5%	5%	5%	1%	-0%	0%
November	-1%	-1%	-0%	-0%	-0%	1%	2%	-1%	-6%	-8%	-7%	-5%	-2%	-1%	-1%	1%	3%	4%	4%	5%	5%	1%	-0%	0%
December	-1%	-1%	-0%	-0%	-0%	0%	1%	0%	-4%	-7%	-7%	-6%	-3%	-1%	-2%	0%	3%	4%	4%	4%	5%	2%	-0%	0%

Metered data collected from systems operating in 2023 confirm the prevalence of energy arbitrage and self-consumption as primary operating modes within the residential sector. Self-consumption is observed only with PV paired systems, but TOU arbitrage is observed across paired and standalone systems. The big difference in the residential sector is the timing of charge. Operating modes within the nonresidential sector are more nuanced given the significant heterogeneity of facility types and load profiles, along with how the demand charge component impacts a customer bill. We examined the monthly impact of storage discharge on facility demand or power (kW) within the nonresidential sector. If storage is discharged to minimize or reduce monthly demand charges, then examining the change in peak demand over the month from a baseline of no storage may reveal that economic prioritization. Figure 4-54 exhibits the percentage of sampled nonresidential customers who either 1) reduced their monthly peak demand (Reduced Peak), 2) experienced no demand increase (No Change) or 3) added to their monthly peak with how they utilized their energy storage system (Added to Peak). The distributions are categorized by presence of on-site PV generation or not and summer versus winter months for each nonresidential budget category. Demand charges are a significant component of nonresidential customer bills, so utilizing the storage system to reduce monthly demand and coincident peak demand are critical ways to realize bill savings.

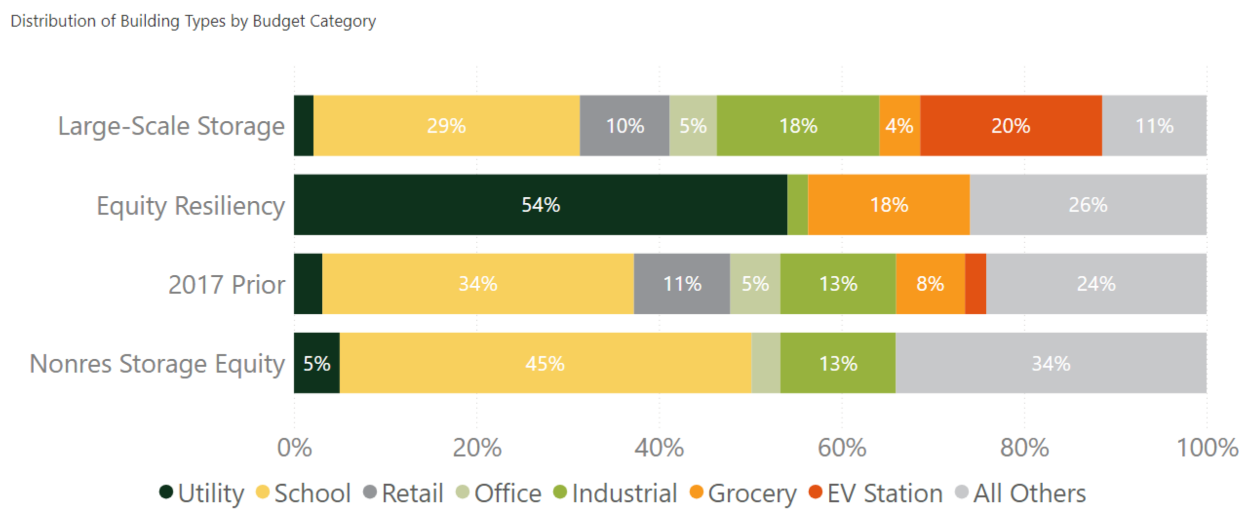
The percentage of projects reducing monthly peaks during the year differs little by season, but markedly by budget category. A greater percentage of projects reducing monthly peaks makes sense – if facility peak 15-minute power at a facility was reduced 50 kW by battery discharge in July for example, the customer will realize demand charge savings compared to baseline of no storage. We observe a significant percentage of idle systems in some budget categories (in particular, older vintage systems) – which contribute to no change in monthly facility maximum load – and systems that increase their monthly peak demand. The latter behavior would suggest a customer realized an increase on the on-bill demand portion of their bill. This behavior is more common with standalone systems, and later in the calendar year as well.

FIGURE 4-54: DISTRIBUTION OF MONTHLY NONRESIDENTIAL PEAK DEMAND IMPACTS



The greater share of projects reducing monthly peak demand, especially in the Nonresidential Storage Equity (81% of system paired or co-located with PV during Summer months) and the greater share of projects increasing monthly peak demand in the ERB category (62% in the same category) is correlated with the distribution of facility types in that budget category. Figure 4-55 highlights the distribution of energy storage installations by building type. Energy storage installed and operable in primary and secondary schools – paired with PV or standalone – are regularly reducing non-coincident peak. As evident above in Figure 4-40, public utility facilities like wastewater treatment plants regularly increase their load relative to a baseline of no storage.

FIGURE 4-55: DISTRIBUTION OF BUILDING TYPES BY BUDGET CATEGORY



We also examined monthly peak demand reductions relative to system capacity by calculating the difference between the highest 15-minute demand (kW) in the absence of storage – the counterfactual baseline – and the highest metered 15-minute demand during each customer bill period. Verdant then normalized that difference by the kW capacity of the system. A customer would realize billed demand savings if the difference between the observed and baseline was positive. It also signals the maximum system capacity used for non-coincident demand reduction. For example, where monthly baseline load would have been 100 kW in the absence of storage and the peak observed load was 80, that delta represents the change in billed demand of 20 kW. If this demand reduction was serviced by a 20 kW system – which would be discharging at full capacity in this example – the reduction would represent 100% of capacity. With a 100-kW system, utilization would be at 20% of capacity.

Figure 4-56 conveys those results for the nonresidential sector by month and budget category. We observe variability in average customer peak demand reductions (and increases) across budget category and throughout the year. Storage equity projects realize the greatest monthly demand reductions as a percentage of system kW capacity, ranging from 13% of rebated capacity to 28%. Older systems (labeled 2017 prior) exhibit much lower monthly demand reductions – ranging from 1% of kW capacity to 10%.

Equity Resiliency projects increase load, on average, especially during the latter months of the year. This is consistent with the more prevalent increase in load during those months presented above.

FIGURE 4-56: MONTHLY PEAK DEMAND REDUCTION (KW) PER REBATED CAPACITY (KW)

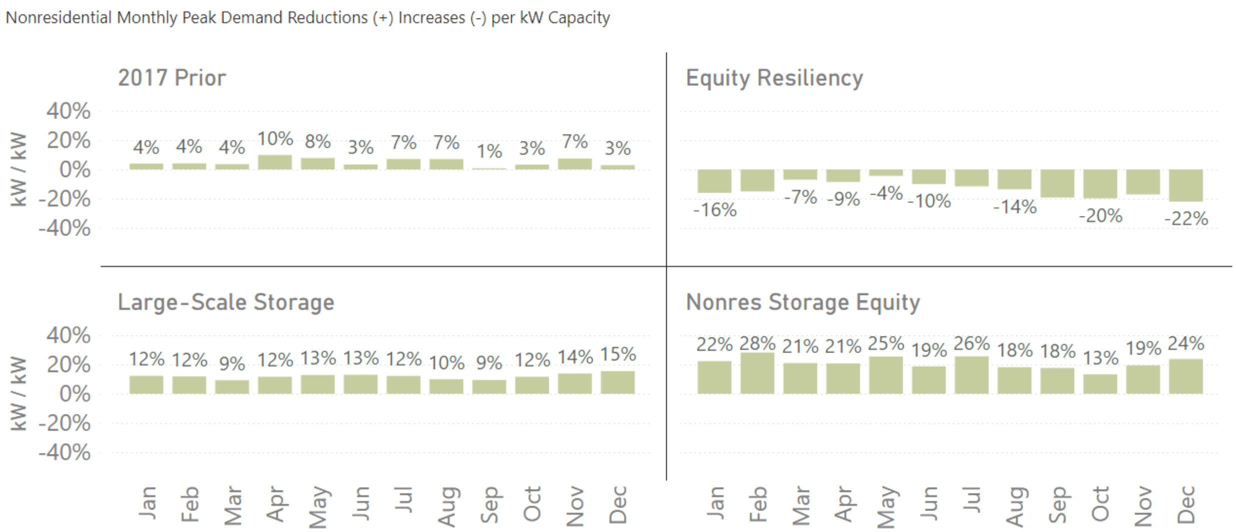
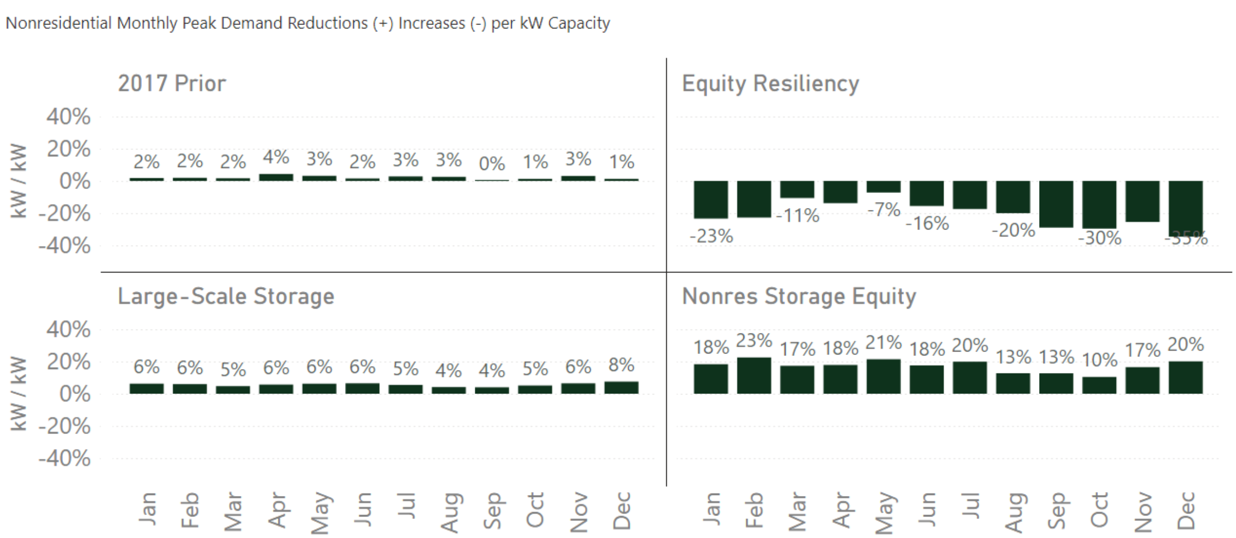


Figure 4-57 conveys the monthly average peak demand reduction as a percentage of a customer's monthly avoided peak. An example case is, if a customer's monthly peak demand would have been 100 kW in the absence of the storage system and they reduced peak demand by 10 kW with storage discharge, then the customer reduced their peak demand by 10%.

FIGURE 4-57: MONTHLY PEAK DEMAND REDUCTION (KW) PER AVOIDED PEAK (KW)



Verdant also reviewed changes in monthly demand by time of day. While older vintage projects (2017 prior) and system installed via the equity or large-scale storage budget category reduced monthly demand, on average, we do observe variations in summer peak demand by time of day. For example, equity projects, reduced demand during most hours of the day, but we observe 15% increase in demand during the 9pm – 12am hours. This is true for older vintage systems and large-scale storage projects. This reflects customers charging the system just after the on-peak period. Equity Resiliency projects exhibit the opposite. They realize demand increases during all hours of the day but realize reductions in demand during the on-peak period where the greatest magnitude of system discharge occurs. This is confirmed below in Figure 4-59.

FIGURE 4-58: SUMMER PEAK DEMAND REDUCTIONS BY TIME OF DAY

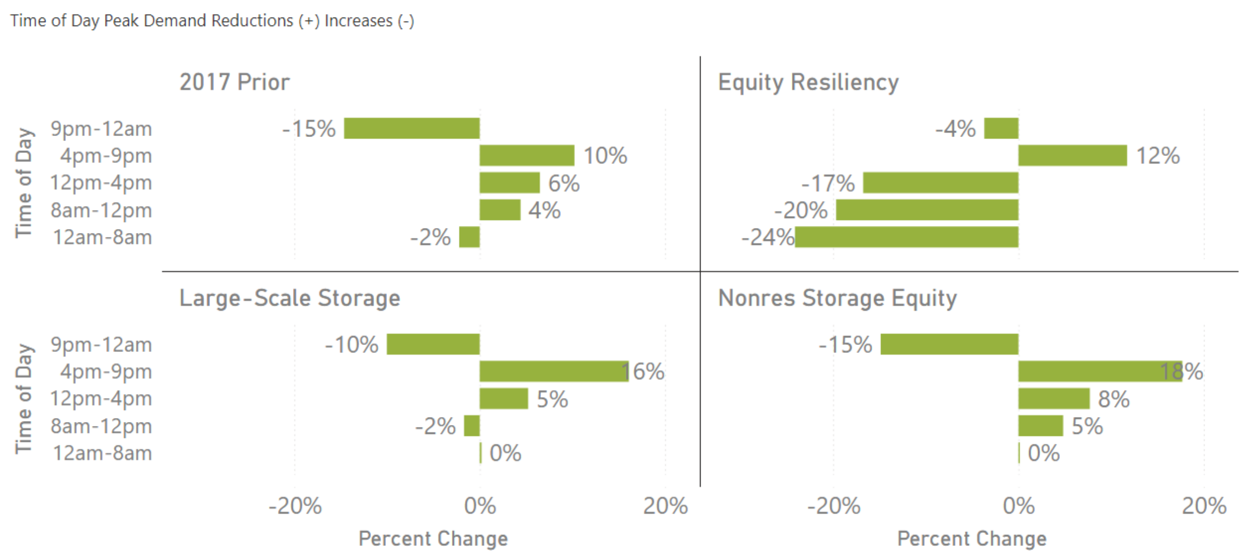
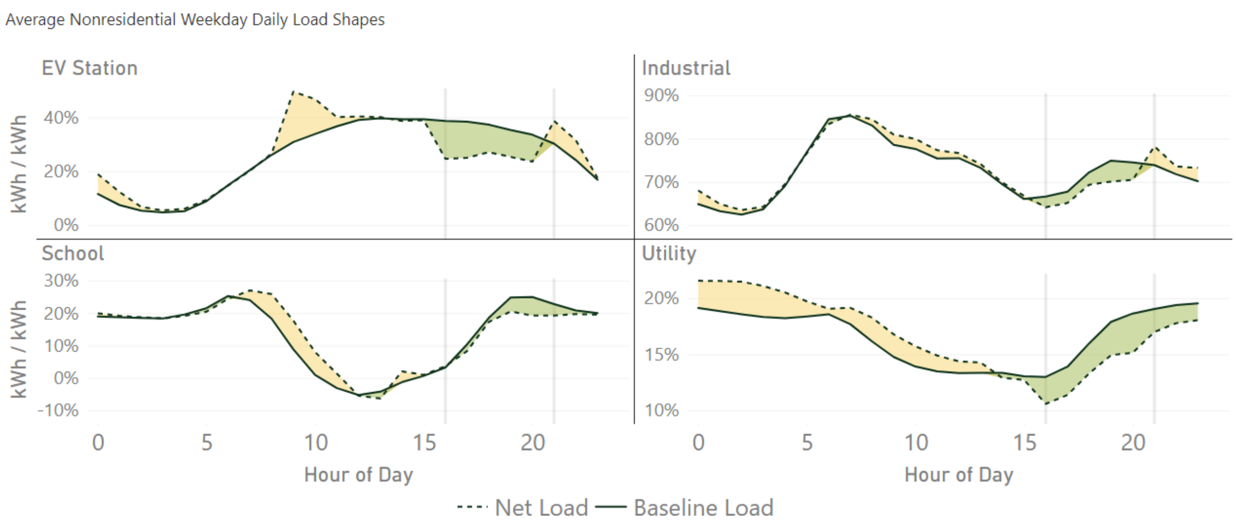


FIGURE 4-59: NONRESIDENTIAL PEAK DEMAND IMPACTS BY BUILDING TYPE



Finally, we summarize per project peak demand changes by system capacity and facility size. Figure 4-60 through Figure 4-62 summarizes these impacts across month for each project. The horizontal axis for each exhibit represents the monthly peak demand reduction, as a percentage of rebated capacity, for each system and the vertical axis represents the monthly peak demand reduction for each system relative to their avoided peak demand. The first exhibit differentiates projects by on-site PV presence, the second by budget category, and the third by building type. Each project budget category is also provided, and the size of the bubble corresponds to the relative size in kW capacity of the system. Overall, we observe a wide range of peak increases and reductions – as a percentage of both energy storage size and customer baseline load.

Individual projects vary considerably with distributions ranging from a peak reduction of 100% of rebated capacity to a peak *increase* 100% of rebated capacity for a system paid in 2017 or prior. Monthly peak demand reductions – as a function of peak facility load – range from 100% to increases approaching 200% of baseline peak facility load.

FIGURE 4-60: NONRESIDENTIAL PEAK DEMAND IMPACTS BY PRESENCE OF ON-SITE GENERATION

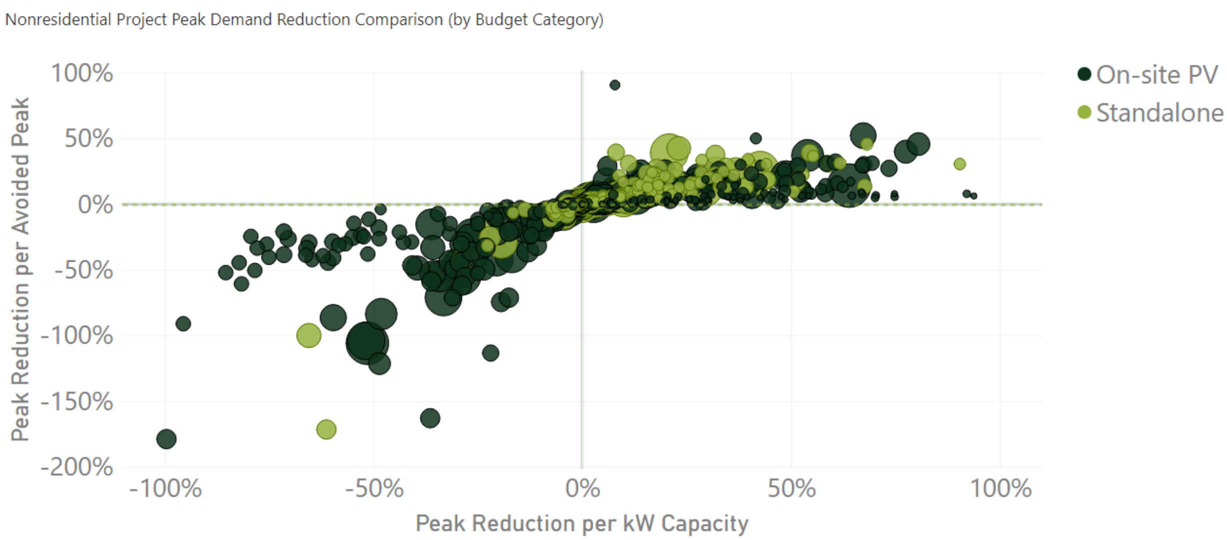


FIGURE 4-61: NONRESIDENTIAL PEAK DEMAND IMPACTS BY BUDGET CATEGORY

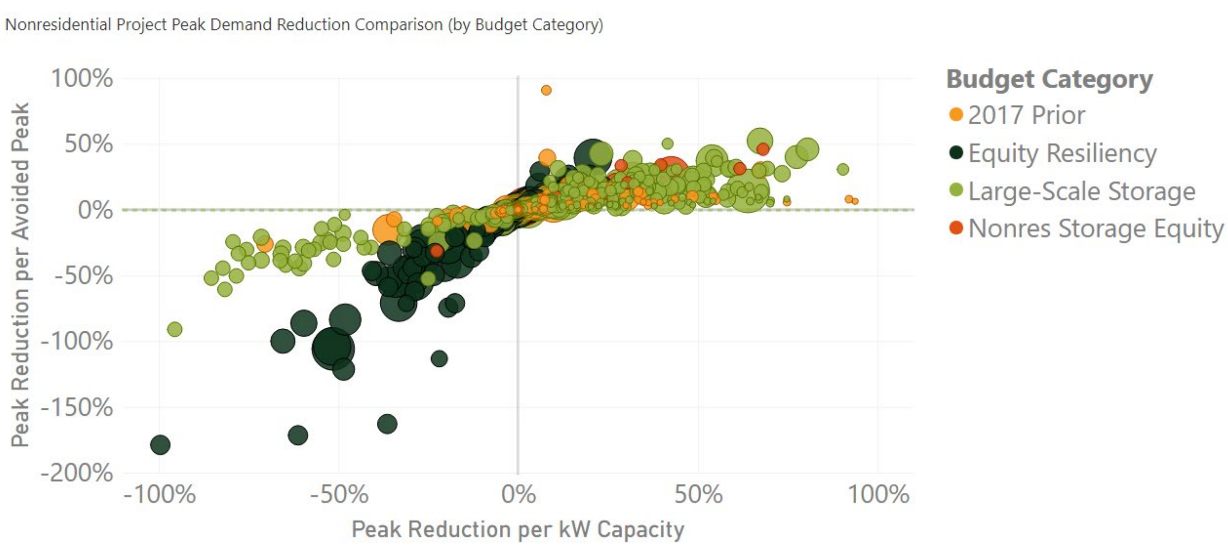
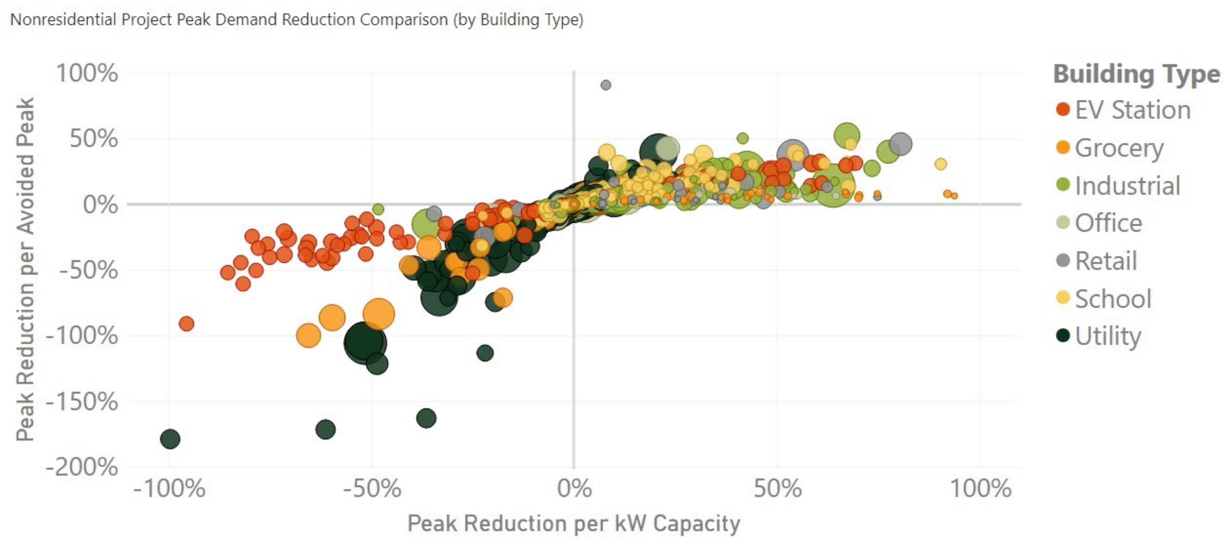


FIGURE 4-62: NONRESIDENTIAL PEAK DEMAND IMPACTS BY BUILDING TYPE



Overall Storage Dispatch Behavior by Customer Rate Group

Verdant also analyzed how storage dispatch behavior differs by customer rate schedule. We employed our distributed energy resource cost-effectiveness analysis tool (DER CAT) to estimate customer bills, leveraging utility rate information alongside AMI hourly-level load data. This sophisticated model incorporates a granular understanding of individual rate charges, demand charges, and variations in time-of-use charges across hours of the day, weekdays, weekends, holidays, and seasonal changes. This information is harnessed to determine the cost of usage for each hour by aligning rate charges with the corresponding date and time of usage, and subsequently aggregating these charges to derive a monthly bill. The inclusion of disaggregated rate charges enables us to discern the various demand charges and energy charges, given the model's comprehensive information into the dynamics of these charges.

Figure 4-63 presents the distribution of on-peak periods by IOU for sampled SGIP nonresidential customers. The 4pm – 9pm summer on-peak is by far the most prevalent. A small percentage of projects haven’t transitioned over to the new on-peak period and, in 2023, were still on a rate with a legacy on-peak.

FIGURE 4-63: DISTRIBUTION OF PEAK PERIODS FOR NONRESIDENTIAL CUSTOMERS (BY IOU)

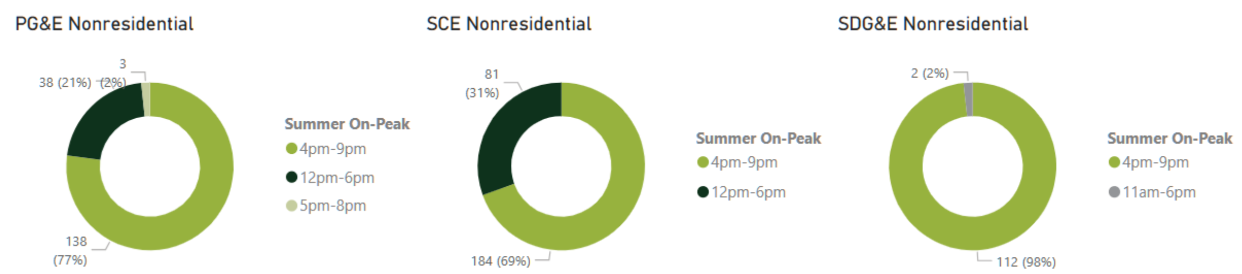
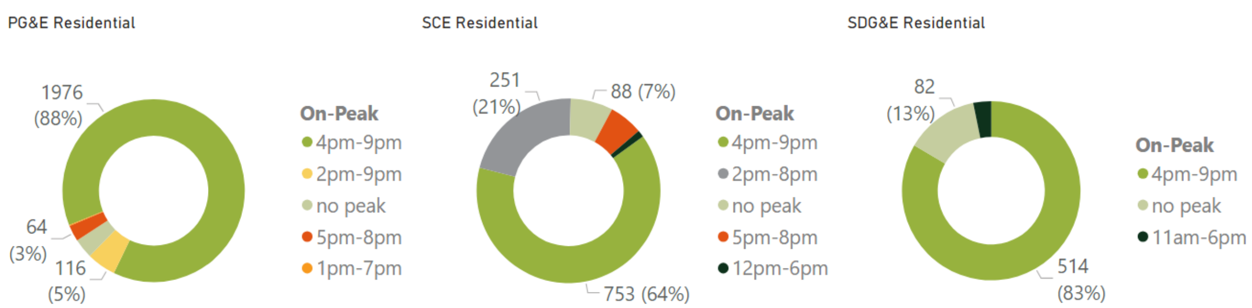


Figure 4-64 presents the proportion of TOU rates versus non-TOU volumetric rates for each of the IOUs in the residential sector, along with the prevalence of the on-peak period. Residential customers with a verified rate schedule were on some type of volumetric or TOU energy rate in 2023. As indicated by the green bar, most residential SGIP participants are on a rate which assesses higher energy prices during the 4pm – 9pm summer period.

FIGURE 4-64: DISTRIBUTION OF TOU VS NON-TOU RATES FOR RESIDENTIAL CUSTOMERS (BY IOU)



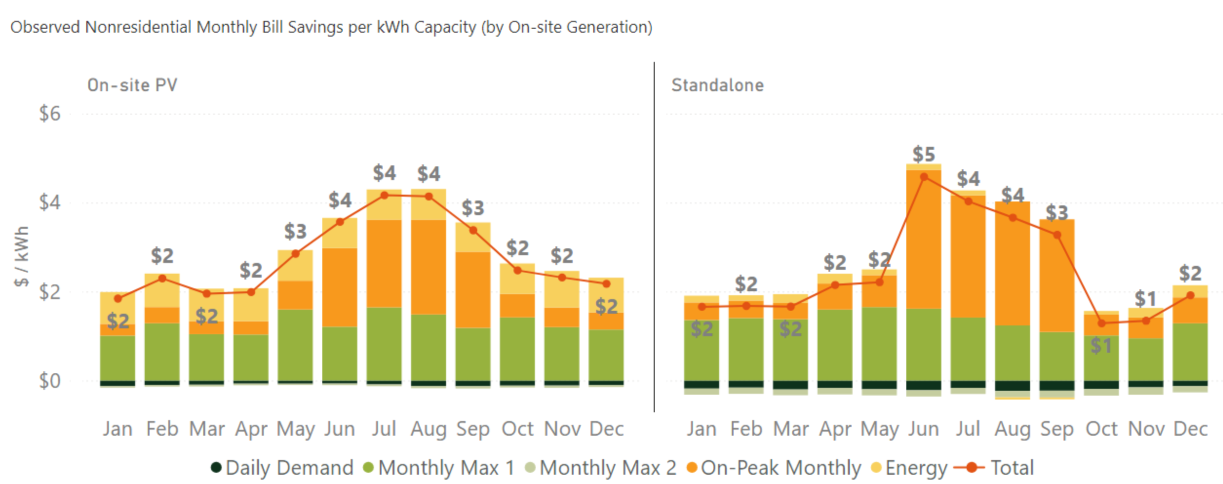
Nonresidential Bill Savings ($/kWh)

Verdant compared the observed billed energy for each TOU period to baseline billed energy impacts. For customers with demand charges, we further estimated the reduction (or increase) in peak demand at a monthly level and during specific TOU periods to calculate demand savings (or increased cost) based on the customer rate schedule. A customer could realize bill savings if they are arbitraging – discharging during on-peak TOU and charging during periods of lower prices – and the price differential between on- and off-peak is sufficient to negate RTE losses. Demand charge savings are realized at the monthly, on-peak, or daily period and may be prioritized at the expense of TOU energy arbitrage.

Nonresidential bill components modeled in this study include: 1) **Daily demand –** a daily on-peak and partial-peak demand charge assessed to medium and large nonresidential PG&E customers with energy storage (Option S). The daily demand charge replaces the per month peak and off-peak demand charge, 2) **Monthly Max 1 –** the standard maximum monthly non-coincident demand charge. For Option S customers, this demand charge is reduced dramatically compared to an equivalent non-Option S rate in PG&E, 3) **Monthly Max 2 –** a monthly demand change assessed to PG&E Option S customers only (but excludes hours between 9am – 2 pm), 4) **On-Peak Monthly** – a monthly maximum demand charge assessed during on-peak and partial-peak (where applicable) periods as defined by the customer rate, 5) **Energy** – the total energy component billed during the month, and 6) **Total** – the sum of the bill parts.

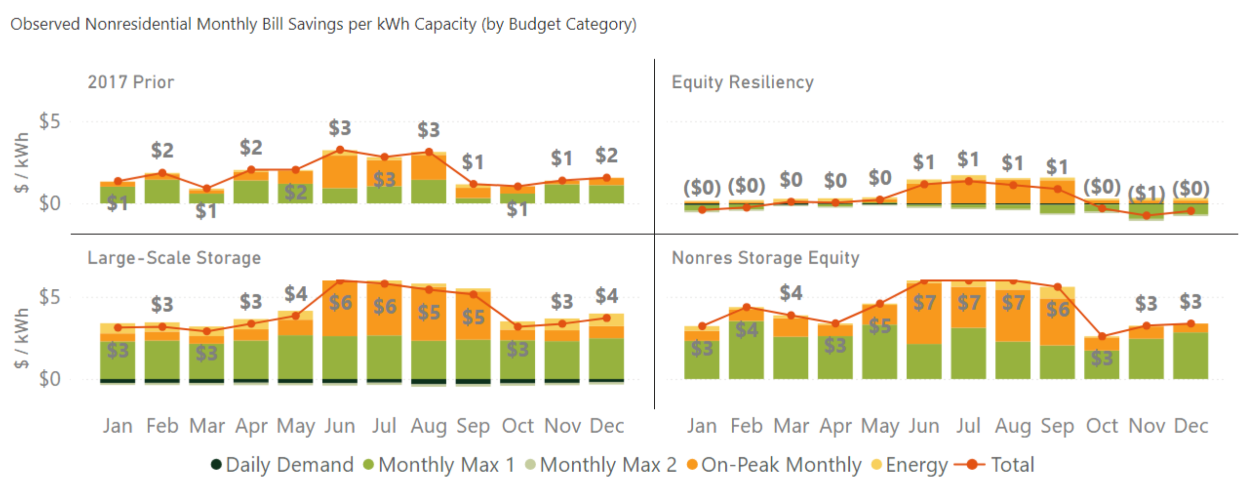
Figure 4-65 presents the results for nonresidential customers by month and presence of on-site PV generation. The vertical axis represents the average monthly savings (+) or bill increases (-) in dollars, normalized by the capacity kWh of the storage system. On average, nonresidential storage dispatch behavior allowed customers to realize overall bill savings for each month of 2023. Overall bill savings are greatest during summer months for both PV paired and standalone systems. Standalone systems realized the greatest savings of $5 per kWh of capacity reduction in June, where PV paired systems averaged $4/kWh during July and August. Observed differences include, 1) standalone systems reduced peak and partial-peak demand (On-Peak Monthly in orange) more significantly from June through September than PV paired systems, 2) PV paired and standalone systems realized energy (yellow bar) and non-coincident demand savings (green bar), and 3) customers on the daily demand charge rate incurred slight increases on the bill. The modeling for customers enrolled on this rate assumes a similar non-Option S rate in the baseline. Those rates don't have a daily demand or the Monthly Max 2 demand charge, so those charges are assessed only on the post-retrofit bill.

FIGURE 4-65: NONRESIDENTIAL CUSTOMER BILL SAVINGS ($/KWH) BY MONTH AND PV PAIRING



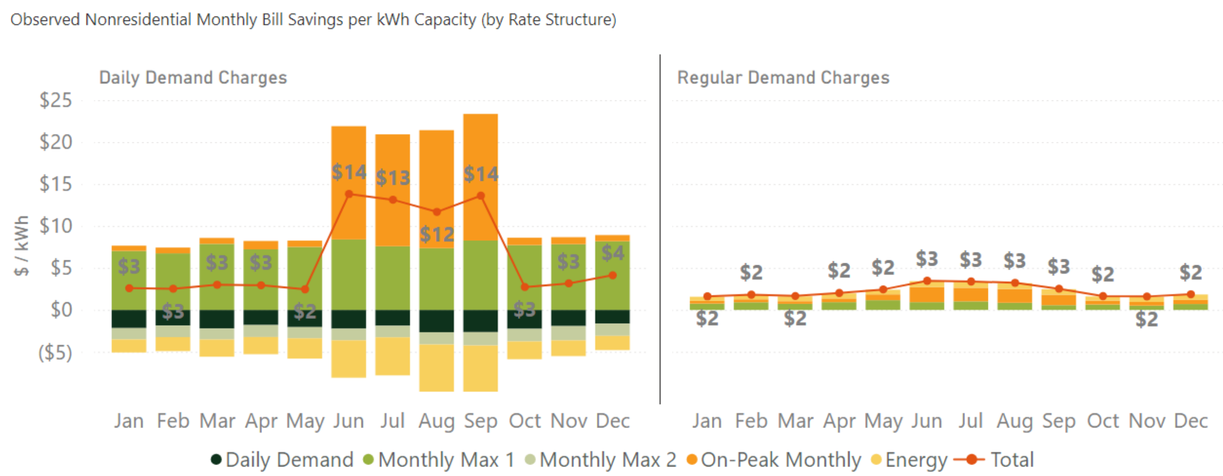
Average monthly bill impacts were also developed by budget category to better capture the different dispatch behaviors observed and discussed above, particularly those found in the ERB (Figure 4-66). We observe many customers increase their non-coincident monthly peak demand in that budget category – with medium duration energy storage systems discharging from 1 pm to 12 am during summer months. Discharging exclusively during that period also leads to reductions in peak and partial-peak demand (orange bars above). While other budget categories realize maximum monthly demand reductions (Non-Coincident Demand), ERB projects incur increases on that component of the bill. Charging overnight typically leads to a new maximum, which translates over to the observed bill increase on the maximum/non-coincident peak (Non-Coincident Demand and the green bar). Non-residential Storage Equity and Large-Scale Storage projects realize the greatest bill savings, on average.

FIGURE 4-66: NONRESIDENTIAL CUSTOMER BILL SAVINGS ($/KWH) BY MONTH AND BUDGET CATEGORY



We also differentiate bill impacts by those assessed daily demand charges compared to those assessed regular per month demand charges only (Figure 4-67). Both rate groups contribute to a reduction in customer bills based on the magnitude and timing of energy storage charge and discharge behavior, along with the $ charges associated with the pre- and post-bills. Customers with daily demand charges realized far more significant bill savings, which may be driven by the more forgiving rate structure compared to the base schedule as well as the impacts from storage charge and discharge performance in the post-bill.

FIGURE 4-67: NONRESIDENTIAL CUSTOMER BILL SAVINGS ($/KWH) BY MONTH AND PV PAIRING



Annual project bill savings (and variance) are displayed below by budget category and on-site PV generation. Monthly impacts have been summed to represent total $ savings (+) or $ incurred (-) in 2023. Individual project bill savings are also presented below in Figure 4-69 through Figure 4-71 by budget category, IOU, and rate structure.

FIGURE 4-68: DISTRIBUTION OF NONRESIDENTIAL OVERALL CUSTOMER BILL SAVINGS ($/KWH)

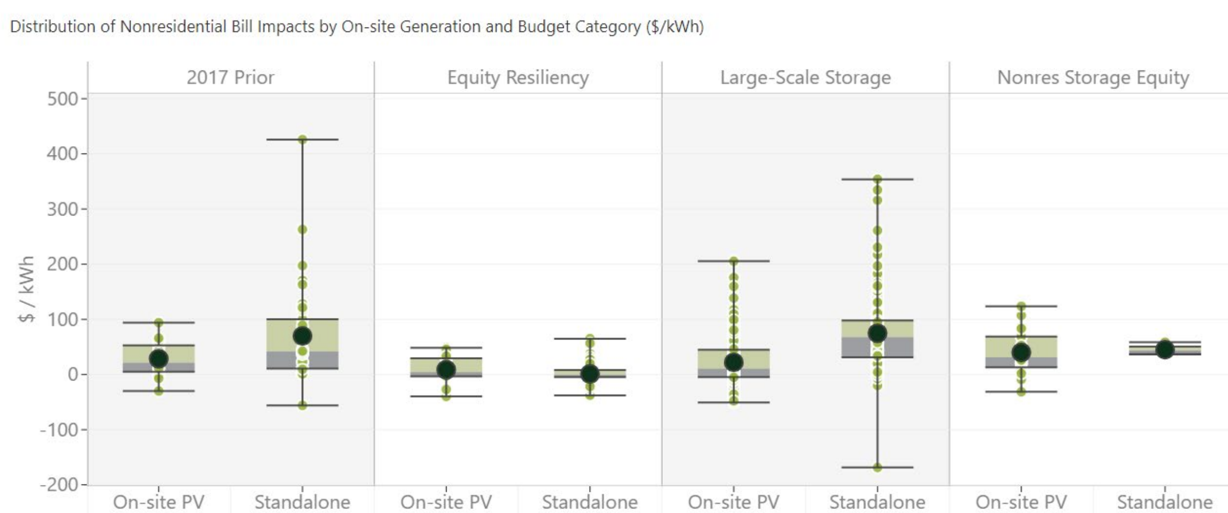


FIGURE 4-69: NONRESIDENTIAL CUSTOMER BILL SAVINGS ($/KWH) BY BUDGET CATEGORY

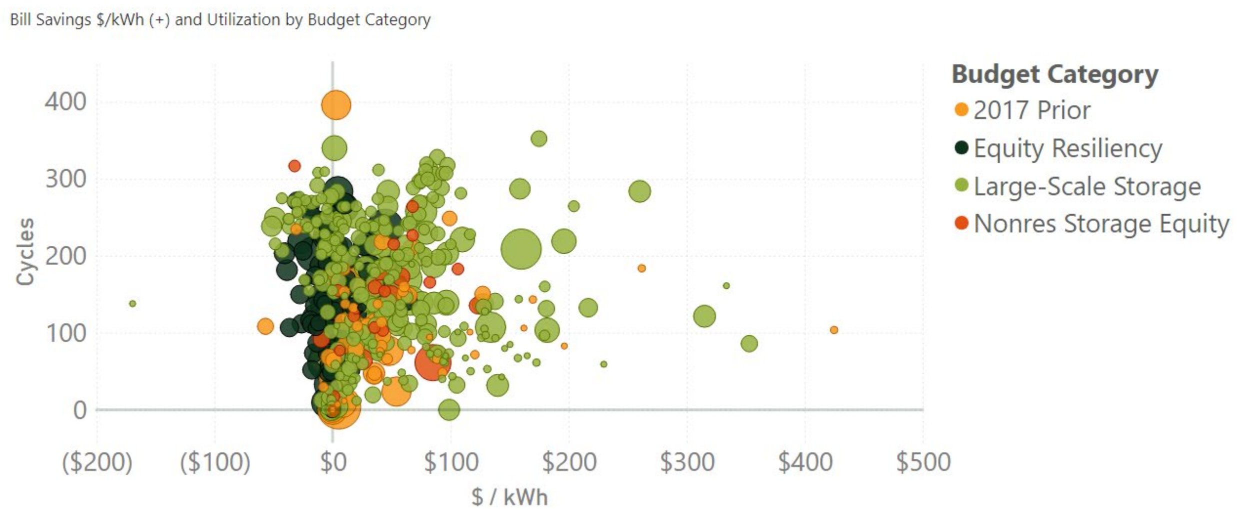


FIGURE 4-70: NONRESIDENTIAL CUSTOMER BILL SAVINGS ($/KWH) BY IOU

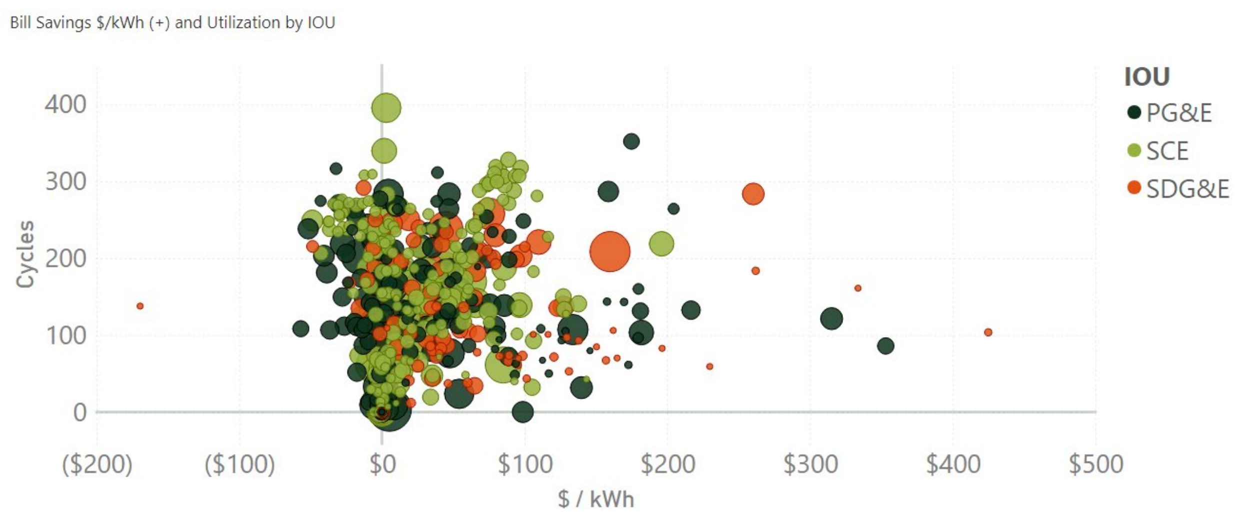
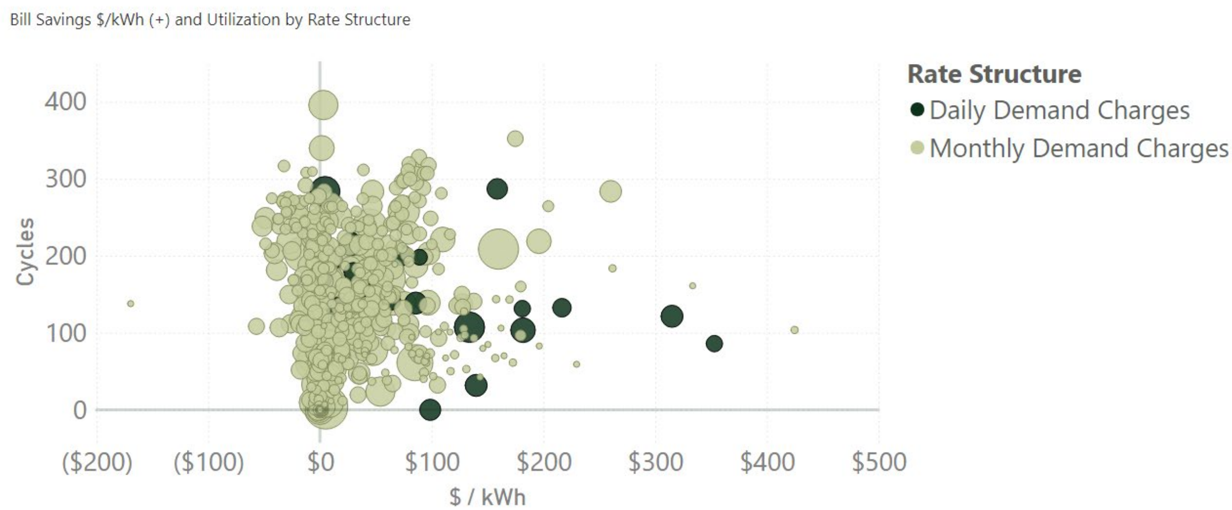


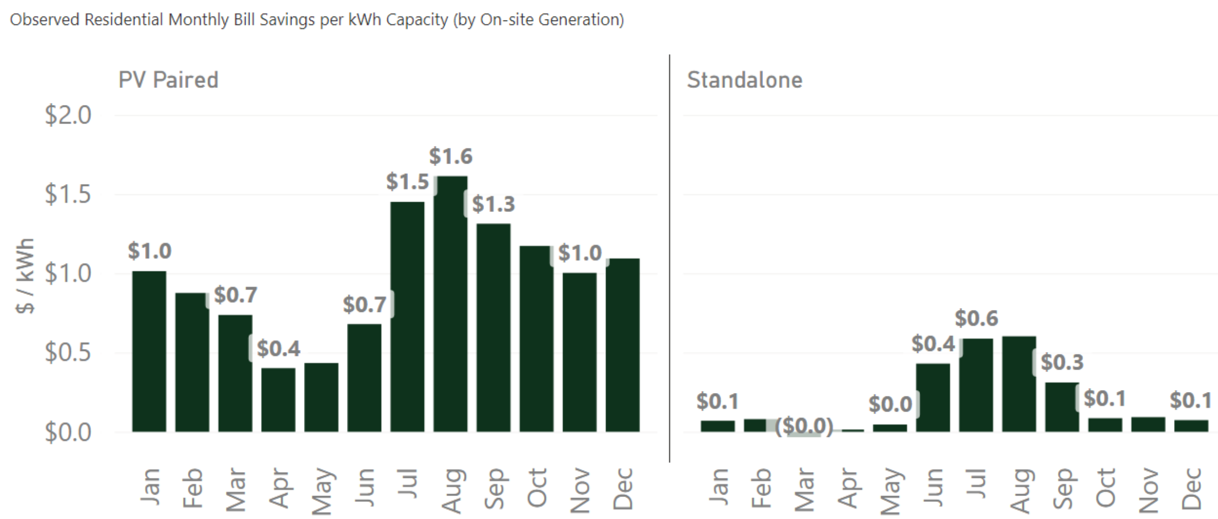
FIGURE 4-71: NONRESIDENTIAL CUSTOMER BILL SAVINGS ($/KWH) BY RATE STRUCTURE



Residential Bill Savings ($/kWh)

Monthly residential bill impacts by standalone and PV pairing are summarized below in Figure 4-72. We observe monthly bill savings for residential customers ranging from as high as $1.60/kWh in August 2023 to as low as $0.40 in April 2023 for paired systems. PV Paired systems are almost exclusively charging from on-site solar – when utilized – and discharging on-peak exclusively for TOU arbitrage or discharging to zero out delivered load during the on-peak period and thereafter. Standalone systems are generally under-utilized compared to PV paired systems. They discharge on-peak and charge overnight, most prominently after midnight.

FIGURE 4-72: RESIDENTIAL CUSTOMER BILL SAVINGS ($/KWH) BY MONTH AND PV PAIRING



Average monthly bill impacts by operating mode are presented below in Figure 4-73. Idle and under-utilized systems unsurprisingly incur small bill increases due to that under-utilization and RTE losses. Time-of-Use arbitrage and self-consumption provide billed savings across each month of 2023, but systems performing arbitrage realize the greatest savings, particularly during July through September, where savings exceed $2.20/kWh on average.

Spring months like April and May exhibit the least savings on average. During those months, many customers have not transitioned to higher on-peak energy rates, and greater on-/off-peak price differentials. Billed rates, combined with significant on-site solar generation with temperatures that preclude A/C and other high demand end uses, allow customers to arbitrage or self-consume at lower utilization. If the system is zeroing out delivered load, and is not exporting, billed savings for these months could be less relative to a baseline (or counterfactual) of no storage.

FIGURE 4-73: RESIDENTIAL CUSTOMER BILL SAVINGS ($/KWH) BY MONTH AND OPERATING MODE

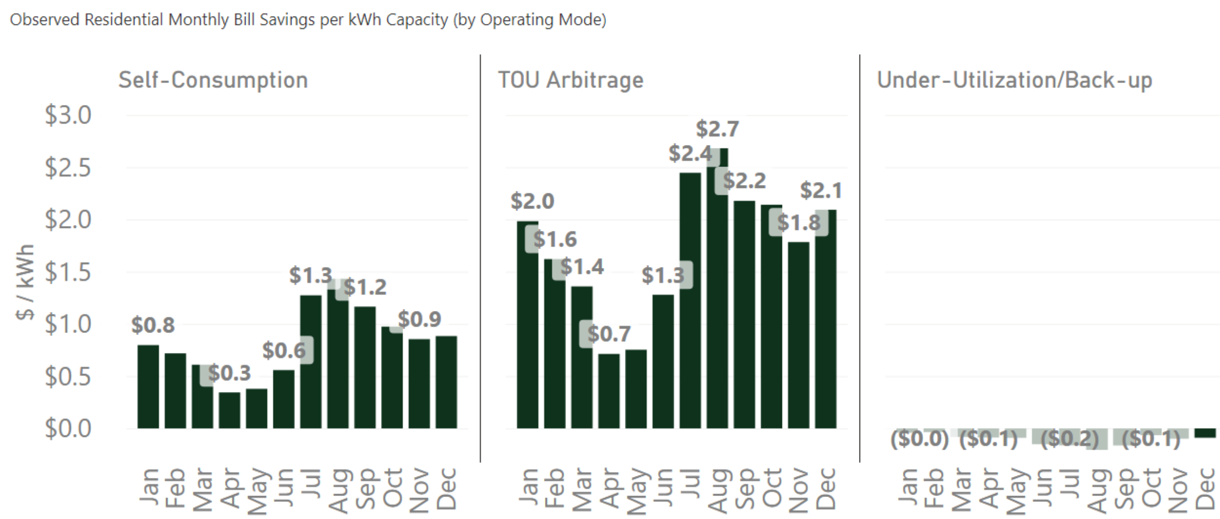


Figure 4-74 exhibits average monthly bill savings by IOU. Bill savings for systems receiving electric service from all three IOUs are greatest in summer months, but we observe differences across IOUs. Systems receiving electric service from PG&E realize lesser savings, overall, with most bill savings realized by customers on the EV-2A rate (roughly $13/kwh annually). Most savings for SDG&E systems are realized from July to October inclusive with the greatest magnitude of savings realized by customers on DR-SES (roughly $11/kWh annually) and EV-TOU-5 (roughly $27/kWh annually). Higher on-/off peak differentials in SCE, especially with the TOU-D-Prime rate ($28/kWh average annual savings), might explain the more consistent bill savings for SCE customers during the year. Average bill savings by rate schedule and IOU can be found below in Figure 4-79. Average bill savings by budget category is also provided in Figure 4-75.

FIGURE 4-74: RESIDENTIAL CUSTOMER BILL SAVINGS ($/KWH) BY MONTH, PV PAIRING AND IOU

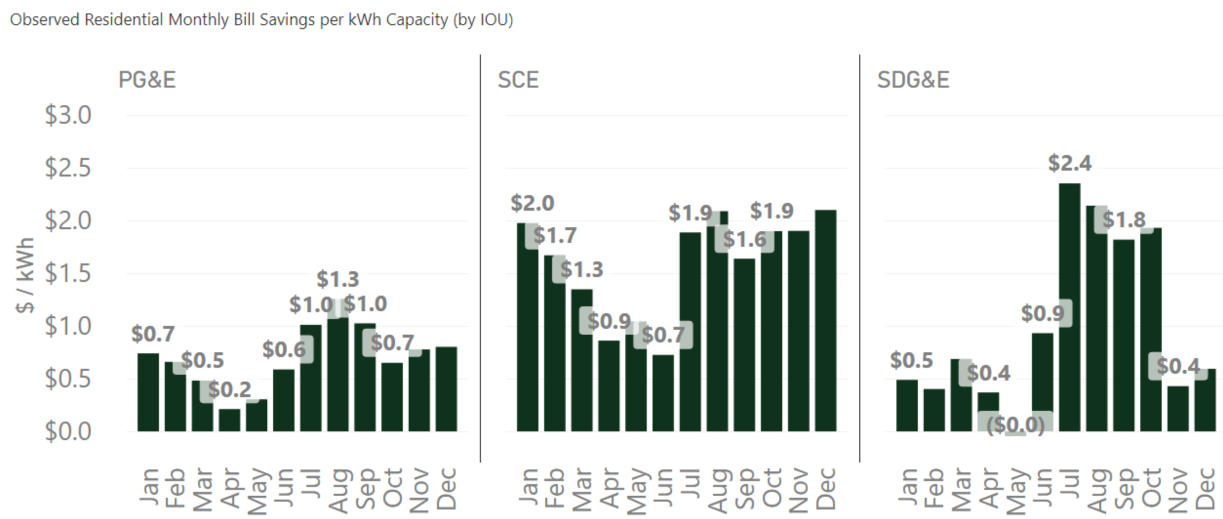
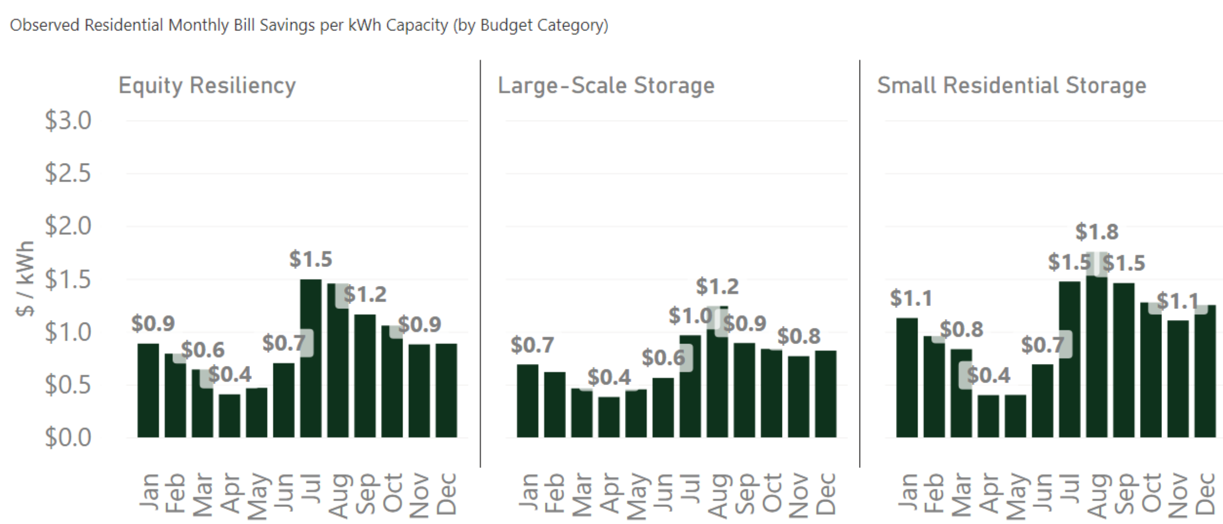


FIGURE 4-75: RESIDENTIAL CUSTOMER BILL SAVINGS ($/KWH) BY MONTH AND BUDGET CATEGORY



Individual annual project bill impacts are presented below in Figure 4-76 and Figure 4-77 by operating mode, and IOU. The horizontal axes represent the bill savings (+) normalized by system kWh capacity, and the vertical axes highlights the utilization – measured in annual cycles – for each project.

FIGURE 4-76: RESIDENTIAL CUSTOMER BILL SAVINGS ($/KWH) BY IOU

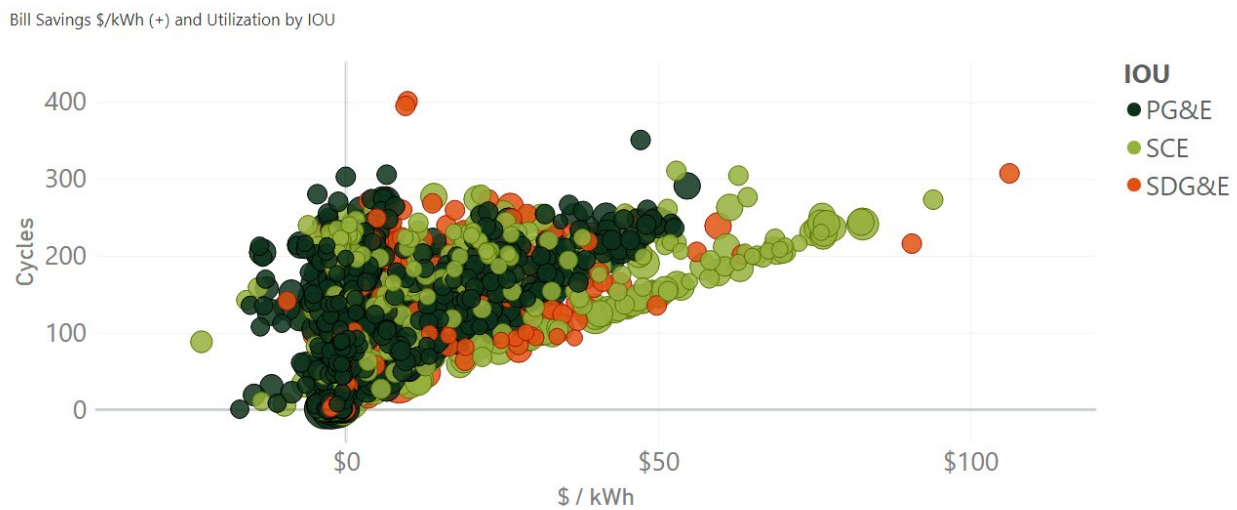
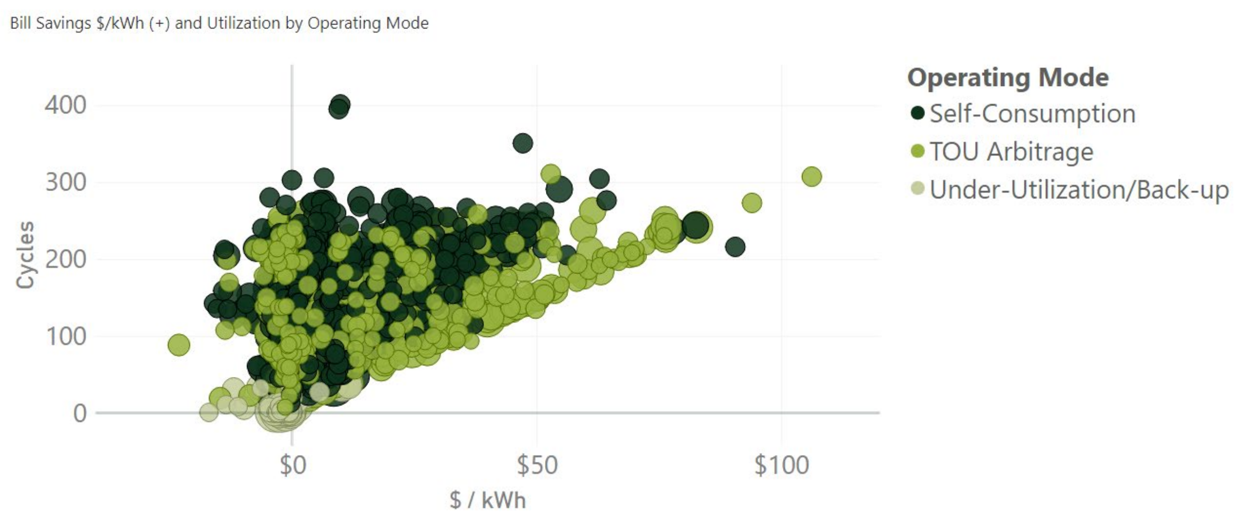


FIGURE 4-77: RESIDENTIAL CUSTOMER BILL SAVINGS ($/KWH) BY OPERATING MODE



Energy Storage Bill Impact Summaries

Below we summarize bill impacts for 2023 by different groupings for the residential and nonresidential sampled sectors.

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FIGURE 4-78: SUMMARY OF 2023 RESIDENTIAL BILL IMPACTS BY IOU

n Prj, Post-Bill, Pre-Bill, Total Bill
BY IOU

IOU	n Prj	Pre-Bill	Post-Bill	Total Bill
PG&E	958	$65	$56	$8
SCE	449	$89	$70	$19
SDG&E	261	$18	$6	$12
Overall	**1668**	**$63**	**$51**	**$12**

FIGURE 4-79: SUMMARY OF 2023 RESIDENTIAL BILL IMPACTS BY IOU AND RATE

n Prj, Post-Bill, Pre-Bill, Total Bill
BY IOU, CUSTOMER RATE

IOU	Customer Rate	n Prj	Pre-Bill	Post-Bill	Total Bill
PG&E	All Others	8	$161	$163	($2)
PG&E	E-TOU-B	28	$43	$43	$1
PG&E	E-TOU-C	266	$63	$64	($1)
PG&E	E-TOU-D	23	$122	$123	($1)
PG&E	EV2-A	605	$63	$49	$13
PG&E	EV-A	28	$56	$49	$7
SCE	All Others	20	$42	$40	$2
SCE	TOU-D-4to9	62	$105	$95	$10
SCE	TOU-D-5to8	65	$57	$48	$9
SCE	TOU-D-A	58	$87	$84	$3
SCE	TOU-D-Prime	244	$97	$70	$27
SDG&E	All Others	42	$7	($2)	$9
SDG&E	DR-SES	73	$17	$6	$11
SDG&E	EV-TOU-5	34	$46	$18	$27
SDG&E	TOU-DR1	112	$14	$4	$9
Overall		**1668**	**$63**	**$51**	**$12**

FIGURE 4-80: SUMMARY OF 2023 RESIDENTIAL BILL IMPACTS BY ON-SITE GENERATION

n Prj, Post-Bill, Pre-Bill, Total Bill
BY ON-SITE GENERATION

On-site Generation	n Prj	Pre-Bill	Post-Bill	Total Bill
PV Paired	1651	$62	$50	$12
Standalone	17	$120	$118	$2
Overall	**1668**	**$63**	**$51**	**$12**

FIGURE 4-81: SUMMARY OF 2023 RESIDENTIAL BILL IMPACTS BY OPERATING MODE

n Prjs, Post-Bill, Pre-Bill, Total Bill Impact
BY OPERATING MODE

Operating Mode	n Prjs	Pre-Bill	Post-Bill	Total Bill Impact
Other/Unknown	12	$84	$83	$1
Self-Consumption	1102	$49	$39	$10
TOU Arbitrage	465	$93	$73	$20
Under-Utilization/Back-up	89	$103	$105	($1)
Overall	**1668**	**$63**	**$51**	**$12**

FIGURE 4-82: SUMMARY OF 2023 RESIDENTIAL BILL IMPACTS BY PAYMENT YEAR

n Prj, Post-Bill, Pre-Bill, Total Bill
BY PAYMENT YEAR

Payment Year	n Prj	Pre-Bill	Post-Bill	Total Bill
2018	77	$81	$73	$8
2019	148	$77	$64	$13
2020	210	$76	$66	$10
2021	630	$64	$52	$13
2022	447	$49	$38	$11
2023	156	$64	$55	$9
Overall	**1668**	**$63**	**$51**	**$12**

FIGURE 4-83: SUMMARY OF 2023 RESIDENTIAL BILL IMPACTS BY BUDGET CATEGORY

n Prj, Post-Bill, Pre-Bill, Total Bill
BY BUDGET CATEGORY

Budget Category	n Prj	Pre-Bill	Post-Bill	Total Bill
Equity Resiliency	476	$56	$45	$11
Large-Scale Storage	77	$73	$64	$8
Small Residential Storage	1113	$66	$54	$13
Overall	**1666**	**$63**	**$51**	**$12**

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FIGURE 4-84: SUMMARY OF 2023 RESIDENTIAL BILL IMPACTS BY EQUIPMENT MANUFACTURER

n Prj, Post-Bill, Pre-Bill, Total Bill
BY MANUFACTURER

Manufacturer	n Prj	Pre-Bill	Post-Bill	Total Bill
Equip 1	1341	$63	$51	$12
Equip 2	133	$103	$93	$10
Equip 3	42	$31	$26	$5
Equip 4	152	$55	$48	$7
Overall	**1668**	**$63**	**$51**	**$12**

FIGURE 4-85: SUMMARY OF 2023 NONRESIDENTIAL BILL IMPACTS BY IOU AND RATE STRUCTURE

n Prj, Monthly , Daily , Non-Coincident , Peak, Energy , Total Bill
BY IOU, RATE GROUP

IOU	Rate Group	n Prj	Monthly	Daily	Non-Coincident	Peak	Energy	Total Bill
PG&E	Daily Demand	24	($17)	($26)	$92	$62	$1	$75
PG&E	Monthly Demand	142	$0	$0	$5	$8	$1	$12
SCE	Monthly Demand	255	$0	$0	$9	$10	$2	$24
SDG&E	Monthly Demand	98	$0	$0	$25	$16	$2	$55
Overall		**519**	**($1)**	**($2)**	**$16**	**$14**	**$2**	**$29**

FIGURE 4-86: SUMMARY OF 2023 NONRESIDENTIAL BILL IMPACTS BY BUDGET CATEGORY

n Prj, Monthly , Daily , Non-Coincident , Peak, Energy , Total Bill
BY BUDGET CATEGORY

Budget Category	n Prj	Monthly	Daily	Non-Coincident	Peak	Energy	Total Bill
2017 Prior	59	$0	$0	$14	$10	$1	$26
Equity Resiliency	123	($1)	($1)	($4)	$7	$2	$3
Large-Scale Storage	311	($2)	($3)	$33	$20	$1	$50
Nonres Storage Equity	26	$0	$0	$24	$15	$2	$43
Overall	**519**	**($1)**	**($2)**	**$16**	**$14**	**$2**	**$29**

FIGURE 4-87: SUMMARY OF 2023 NONRESIDENTIAL BILL IMPACTS BY ON-SITE GENERATION

n Prj, Monthly , Daily , Non-Coincident , Peak, Energy , Total Bill
BY ON-SITE GENERATION

On-site Generation	n Prj	Monthly	Daily	Non-Coincident	Peak	Energy	Total Bill
On-site PV	214	($1)	($1)	$16	$12	$2	$28
Standalone	305	($2)	($2)	$16	$15	$1	$29
Overall	**519**	**($1)**	**($2)**	**$16**	**$14**	**$2**	**$29**

FIGURE 4-88: SUMMARY OF 2023 NONRESIDENTIAL BILL IMPACTS BY SUMMER ON-PEAK PERIOD

n Prj, Monthly , Daily , Non-Coincident , Peak, Energy , Total Bill
BY ON-PEAK PERIOD

On-Peak Period	n Prj	Monthly	Daily	Non-Coincident	Peak	Energy	Total Bill
11am-6pm	2	$0	$0	$6	$0	($1)	$5
12pm-6pm	113	$0	$0	$16	$5	$2	$16
4pm-9pm	401	($1)	($2)	$16	$15	$2	$31
5pm-8pm	3	$0	$0	$7	$23	$3	$32
Overall	**519**	**($1)**	**($2)**	**$16**	**$14**	**$2**	**$29**

4.2.2 Generation

The operational characteristics of several generation technologies influence their impact on customer operations and energy bills. Wind turbines and pressure reduction turbines differ from the others due to the nature of their energy inputs. The supply of wind energy varies with weather, while the supply of steam may vary with facility production levels. Generation technologies relying on gaseous fuels are designed to operate with relatively high capacity factor, and thus offer more potential for consistently impacting noncoincident facility peak demand levels that factor into the calculation of billed demand charges on electricity bills. The impacts of generation systems on customer noncoincident peak demand and electricity exports are presented below.

Customer Noncoincident Peak Demand

SGIP projects impact customer demand in addition to the system (IOU or CAISO) coincident peak demand. It is not always the case that a customer's peak demand falls on the CAISO or IOU peak load hour. The peak customer demand during any stated period is called the customer noncoincident peak (NCP) demand. The impact on a customer's annual peak demand is an important element of the total impact an SGIP system has on a customer's load throughout the year. The demand portion of customer bills is based on the monthly peak kW. Thus, in addition to the reduction in annual peak demand, the monthly demand reduction illustrates how SGIP impacts customer electricity costs.

Approach for Customer Noncoincident Peak Demand Impacts

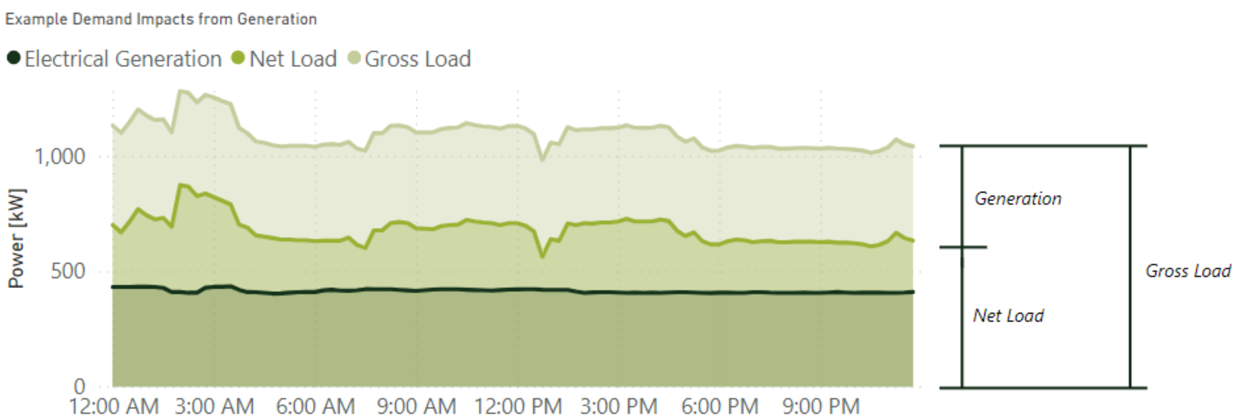
To analyze the impact of SGIP on customer NCP demand, the available utility AMI load data and the generation data are aligned on an hourly basis. The gross demand without the presence of the SGIP generation is then calculated as:[38]

$$Gross\ Load\ (\overline{kW}) = Metered\ Load + Generation - Exported \quad \textbf{EQUATION 4-4}$$

$$Net\ Load\ (\overline{kW}) = Metered\ Load \quad \textbf{EQUATION 4-5}$$

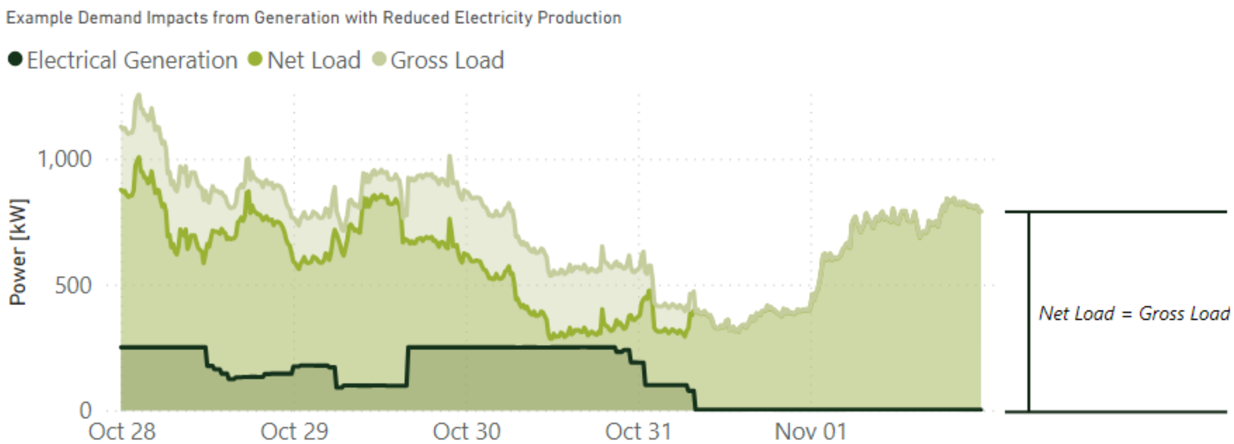
The potential impact of SGIP generators on gross and net load can be seen graphically in the following figures. Figure 4-89 shows an example of how metered NCP customer demand, represented by net load, is reduced by SGIP generation. During 2023, the maximum electrical generation brought the maximum gross peak down, on average, by as much as 96% of rebated capacity. Figure 4-90 illustrates the impact an SGIP generator outage has on NCP customer demand. Depending on the customer load profile, net load during a generator outage or period of reduced electrical production may set the monthly or annual peak demand.

FIGURE 4-89: EXAMPLE DEMAND IMPACTS FROM GENERATOR



[38] For this analysis, demand is calculated as the average power draw within a one-hour period. This is an approximate calculation, as demand is measured in 15-minute intervals and may differ from the hourly average.

FIGURE 4-90: EXAMPLE DEMAND IMPACTS FROM GENERATOR WITH REDUCED ELECTRICITY PRODUCTION



Average NCP Customer Demand Impacts

The weighted average impacts of generation technologies on NCP customer monthly maximum demand are shown below in Figure 4-91 as a proportion of rebated capacity. Electric fuel cell projects, on average, provided customer monthly peak demand savings equal to 41% of rebated capacity. In other words, a customer with a 100 kW fuel cell would see a reduction of their net load of about 41 kW during their monthly peak load hours. IC engines, on average, would reduce customer load by 72% of rebated capacity, and wind turbines were found to reduce the noncoincident peak demand by 49% of rebated capacity. There was insufficient data for CHP fuel cells and Gas Turbines to be able to provide a non-coincident demand analysis for these technologies.

FIGURE 4-91: OBSERVED AVERAGE MONTHLY NCP IMPACTS AS PERCENT OF REBATED CAPACITY

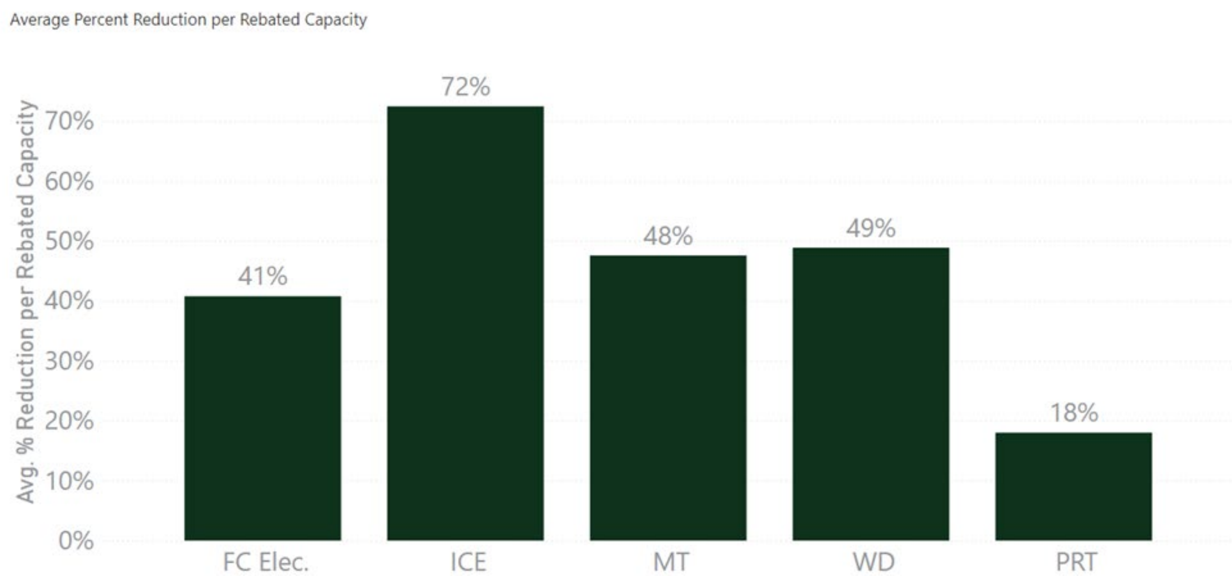
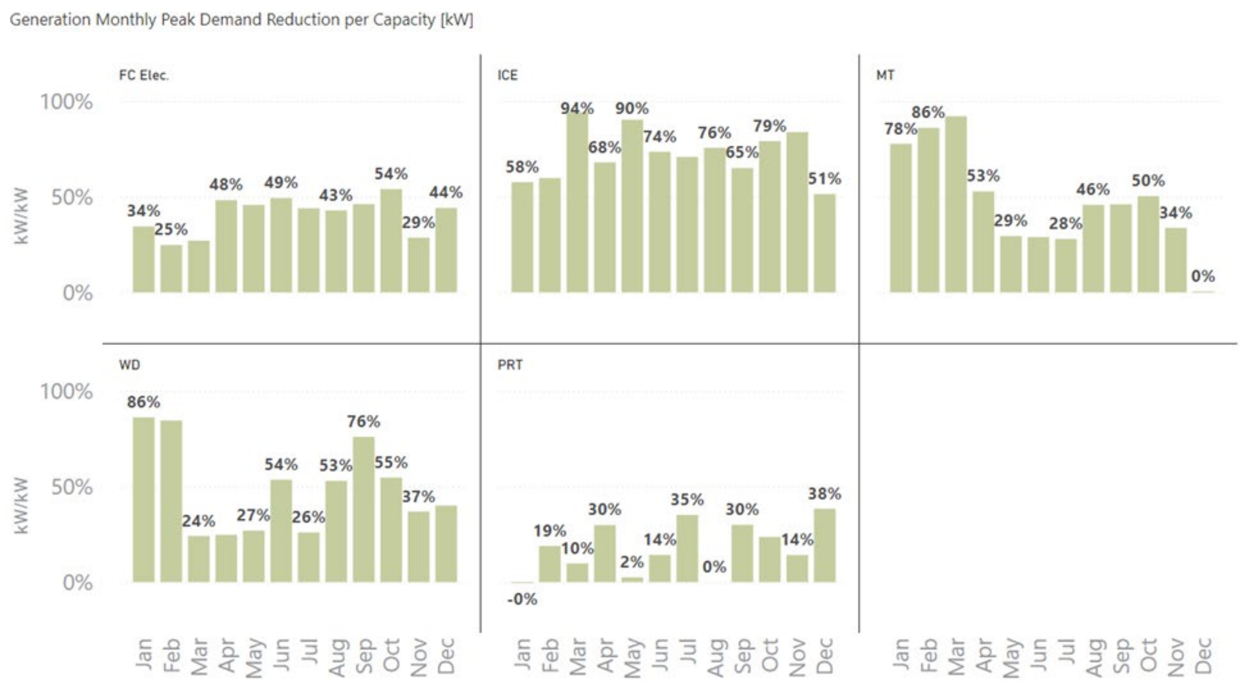


Figure 4-92 shows the same information at the monthly level. Microtubines and wind turbines show the greatest monthly variations, as did pressure reduction turbines, although there are only a few of these projects in the program. While it's difficult to tell the exact reason for variations in operation, many of these variations appear to be due more to differences in site-specific operation than technology-specific use cases. Although generation systems generally provide a baseload, technologies like microturbines and internal combustion engines are easier to ramp up and down than fuel cells, and therefore do have the ability to be shut down or run at a reduced capacity when not needed. Seasonal variations could also be due to unexpected disruptions in facility or SGIP system operations.

FIGURE 4-92: OBSERVED MONTHLY NCP IMPACTS AS PERCENT OF REBATED CAPACITY

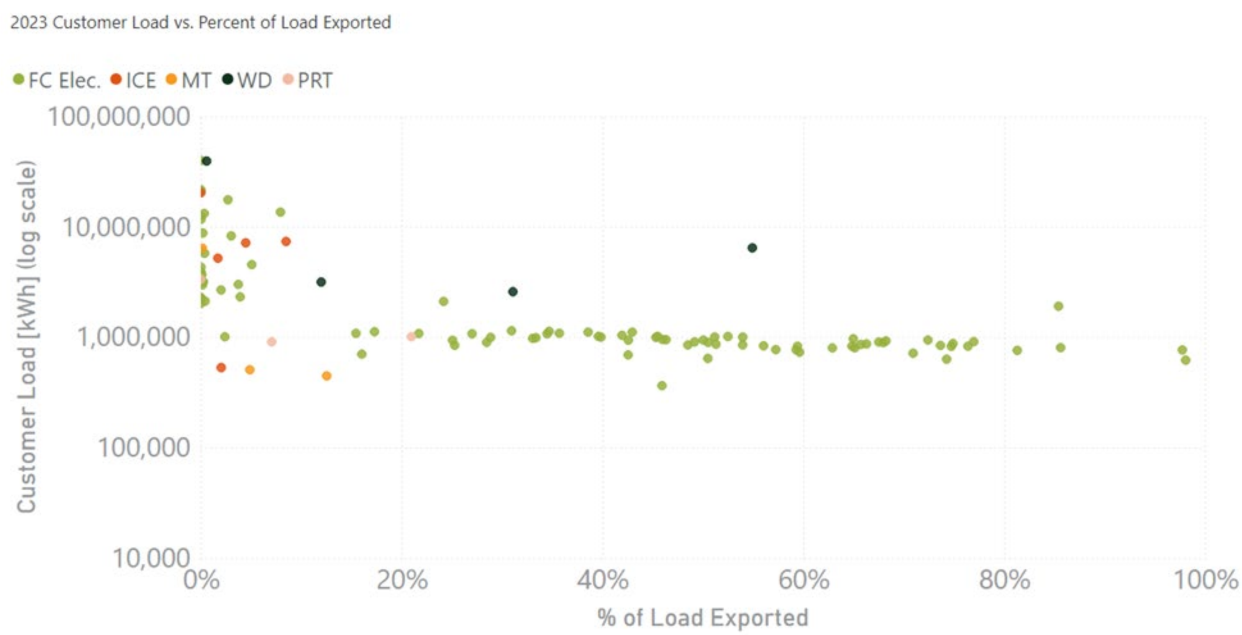


Generation Export

Electricity generation systems are generally designed to be base loaded, meaning they are operated to generate enough electricity to cover the base load needs of a customer. Since at least PY 2011, the SGIP Program Handbook allows SGIP incentivized systems to export a maximum of 25% of their onsite consumption to the grid, on an annual basis. The SGIP handbook clarifies that the PBI payment is calculated based on the generated electricity consumed onsite, and that proof of export documentation may be required prior to payment. However, the handbook doesn't specifically call out projects that have completed their PBI requirements. Forty-five percent of the observed sites in 2023 were exporting over 25% of their energy generated, up from about 15% in 2018, yet all of these projects have already completed their PBI requirements.

Figure 4-93 highlights the percent of load being exported during 2023. In particular, all-electric fuel cells appear to be exporting a large percentage of energy. As we have noted in the last report, many of the customers installing all-electric fuel cells appear to be on power purchase agreement (PPA) contracts, requiring them to purchase 100% of the electricity generated from the systems, even if they are not utilizing all the energy.[39] California saw significant energy constraints during 2020, and in response, Bloom Energy ran an initiative to export significant energy to help relieve the strain on the grid using combustion-free, fuel flexible technologies.[40] It is possible that since this initiative, many Bloom customers have continued to export all unused excess energy.

FIGURE 4-93: CUSTOMER LOAD VS PERCENT OF LOAD EXPORTED ACROSS 2023



Natural Gas Impacts

The use of natural gas fuel by early SGIP systems results in increased pipeline transport of natural gas in California. However, the useful recovery of heat that displaces natural gas boilers reduces the pipeline transport of natural gas. Figure 4-94 below summarizes the project-level observed net impacts on natural gas, displayed as thousand therms per rebated kW. Based on the metered data, these projects result in a natural gas increase around 380 therms per rebated kW, so a 500 kW generation system would increase

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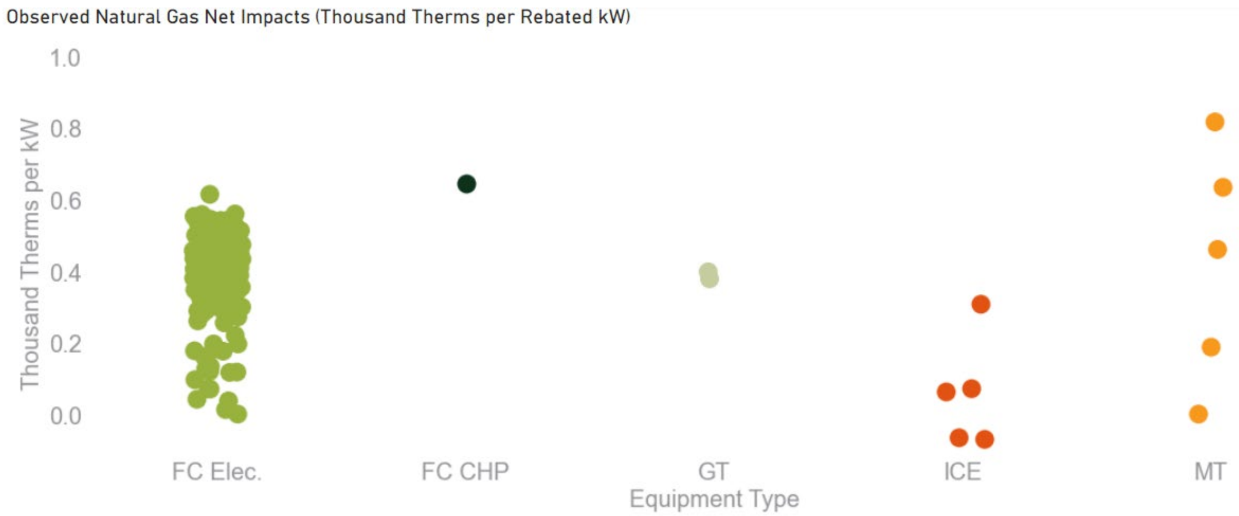
39 Bloom Energy's 2018 July S-1 Statement states "… The end-customer is required to purchase all of the electricity generated by the Energy Servers for the duration of the offtake agreement…" Page 89. https://d18rn0p25nwr6d.cloudfront.net/CIK-0001664703/f332ae61-2c3b-4eff-92b4-8565d1ea9781.pdf. Accessed 10/24/2023.

40 *Local Ordinances Exceeding the 2019 Energy Code. San Jose – 2019 2 Public Comments 3.* Docket Number 19-BSTD-06. Docket Date: 02/12/2021. Page 4. https://efiling.energy.ca.gov/GetDocument.aspx?tn=236754-10&DocumentContentId=69797. Accessed 03/20/2024.

natural gas usage by 190 thousand therms. Microturbines, gas turbines, and all-electric fuel cells have a higher natural gas impact, whereas CHP fuel cells and IC engines were more likely to recover heat, leading to a lower natural gas impact.

FIGURE 4-94: 2023 OBSERVED NATURAL GAS IMPACTS



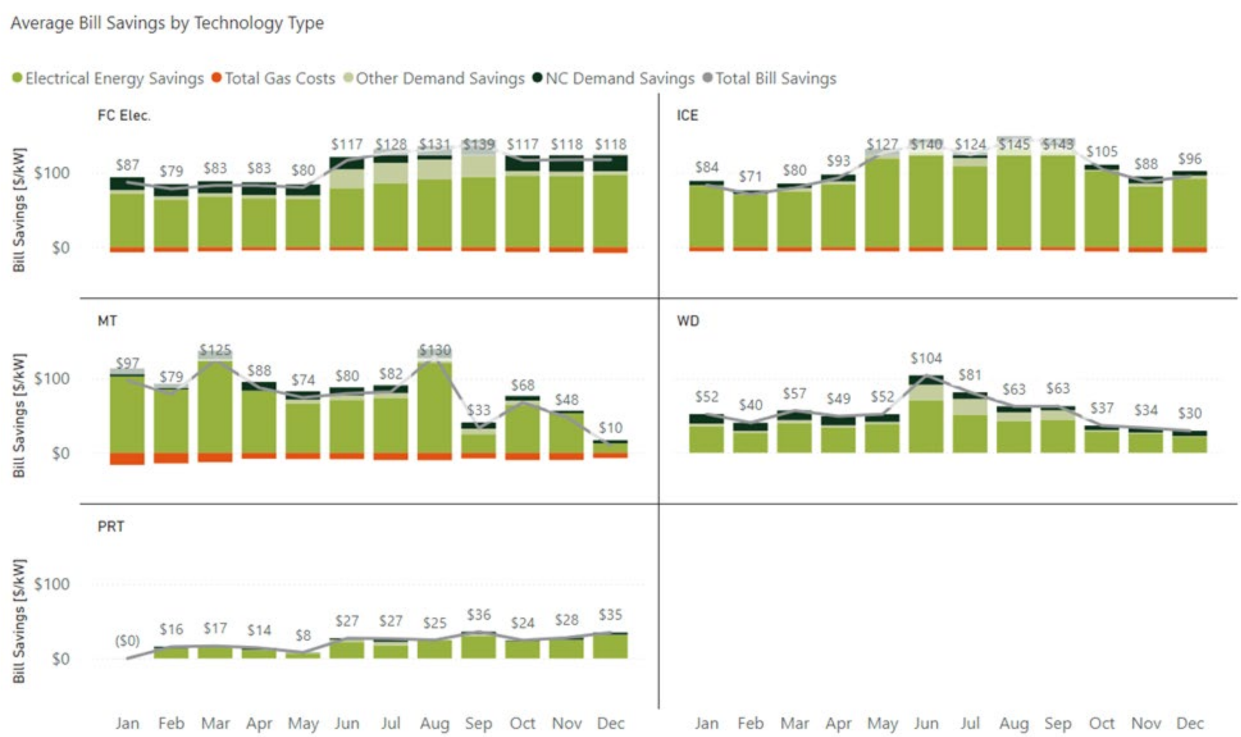
Overall Customer Bill Savings ($/kW) by Technology

Verdant also compared the observed billed energy for each period to baseline billed energy impacts. For customers with demand charges, we further estimated the reduction (or increase) in peak demand at a monthly level and during specific TOU periods to calculate demand savings (or increased cost) based on the customer rate schedule. Demand charge savings are realized at the monthly or on-peak period and may be prioritized at the expense of TOU energy arbitrage. Additionally, Verdant accounted for the cost of the natural gas consumed, and for the projects where heat was recovered, the offset of natural gas from heat recovered feeding into the boiler.

Figure 4-90 presents the results for generation customers by month separated out by technology types. Similar to the storage analysis, the bars correspond to the components of the bill; 1) non-coincident demand represents the maximum monthly demand in $/kW, 2) other demand represents the maximum peak and partial-peak (where applicable) demand in $/kW, 3) electrical energy represents the electrical component of the bill in $/kW, 4) total gas costs are the associated increases in bills due to the additional gas usage, as well as the reduction in boiler fuel usage due to any heat recovery and 4) the total is the sum of bill parts. The vertical axis represents the average monthly savings (or increased cost) in dollars, normalized by the capacity kW of the generation equipment.

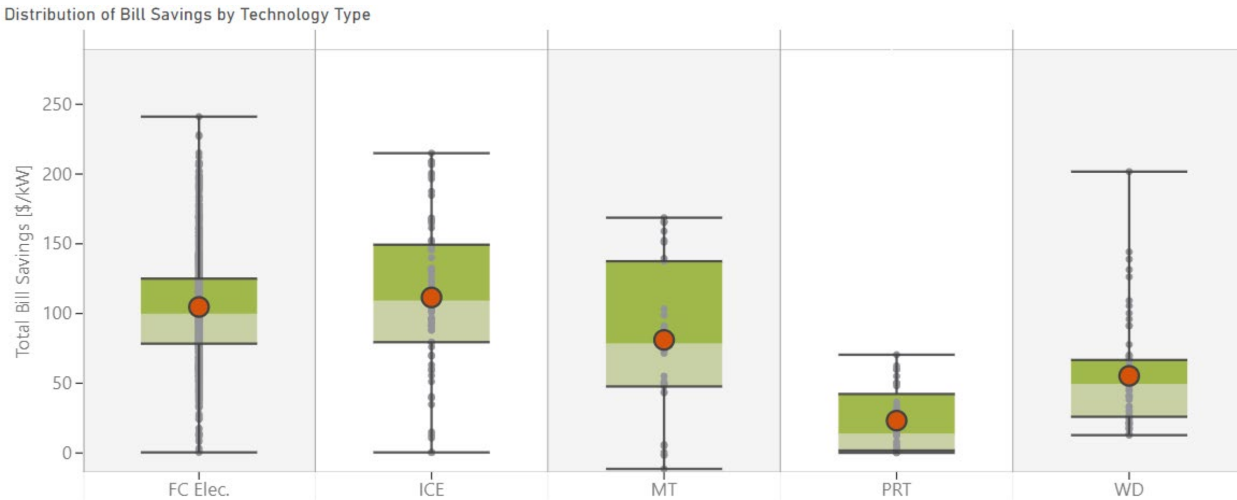
Internal combustion engines saw the largest maximum bill savings, driven by their electrical energy savings during summer months which was up to $145/month, but as low as $71/month, while all-electric fuel cells appear to provide a slightly more consistent year-round bill savings, with January-May savings around $80/month and June-December savings closer to $120/month. Pressure reduction turbines saw the lowest overall bill savings, due to their low capacity factors.

FIGURE 4-95: MONTHLY BILL SAVINGS PER KW BY TECHNOLOGY TYPE



While the figure above highlights the average monthly bill savings, Figure 4-96 displays the distribution of annual 2023 project bill impacts, along with the variance, by technology type. Average savings for all-electric fuel cells, IC engines, and microturbines hover around $100/kW, while wind turbine projects averaged just over $50/kW and PRTs less than $25/kW. However, as can be seen in the Figure, project-level bill savings varied significantly, project by project. We should note that these savings are calculated only for periods of time when a project is within its permanency period, so if a project ended its 10-year permanency period during 2023, or was decommissioned part way through 2023, the results will not reflect a full year of bill impacts. .

FIGURE 4-96: DISTRIBUTION OF 2023 BILL SAVINGS PER KW BY TECHNOLOGY TYPE



4.3 CAISO AND IOU SYSTEM IMPACTS

By generating or discharging during CAISO and IOU peak hours, SGIP project hosts allow their electric utility to avoid the purchase of high-cost wholesale energy. At the same time, the electric utility reduces its transmission and distribution losses during hours of high system congestion. And during extreme events, generating/discharging can even help avoid rolling blackouts. Ideally, SGIP system hosts are generating at full capacity and avoiding system maintenance during peak hours and thus contributing the greatest possible demand impacts. However, these CAISO or IOU peak hours do not necessarily occur when an SGIP system host may want to be generating, therefore a host may not always operate their SGIP system optimally during the grid peak hours.

This section examines generation during CAISO and IOU annual peak "gross" load and "net" load hours as well as their top 100 hours. Table 4-3 lists hours and magnitudes of CAISO and IOU peak demands during 2023. The gross peak CAISO hour occurred August 16th, beginning at 5PM local time, while the net peak hour occurred two hours later the previous day. We show impacts related to both gross and net peak hours.[41]

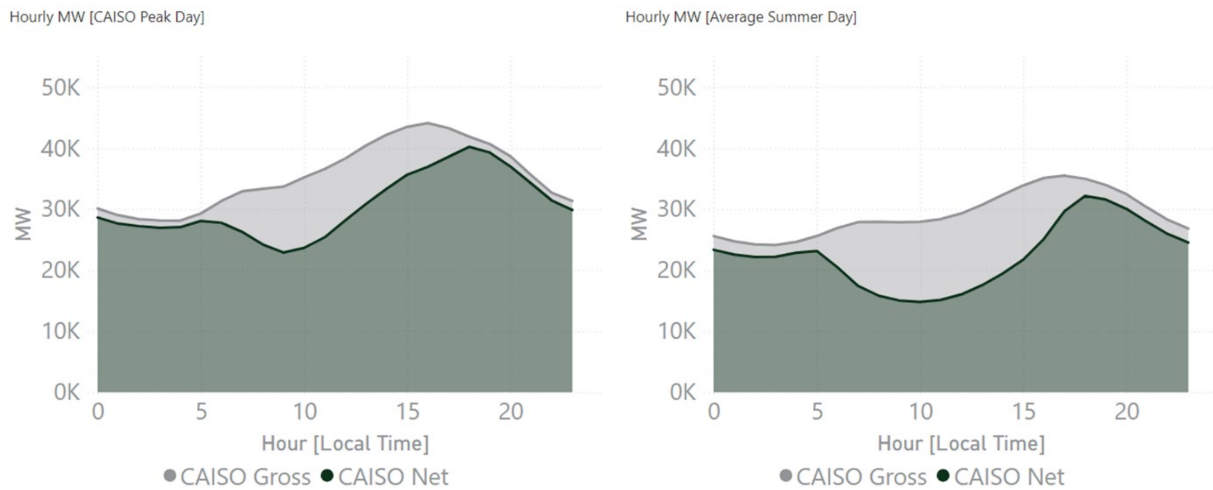
TABLE 4-3: 2023 CAISO AND IOU PEAK HOURS AND DEMAND [MW]

Peak Period	Peak Demand [MW]	Date	Hour [Local Time]
CAISO - Gross	44,092	August 16th	5pm-6pm
CAISO – Net	41,059	August 15th	7pm-8pm
PG&E	19,881	August 15th	6pm-7pm
SCE	22,124	July 26th	4pm-5pm
SDG&E	4,016	August 29th	6pm-7pm

Figure 4-97 highlights the differences between the CAISO gross and CAISO net loads. The right figure represents an average summer day where there is a slight early morning ramp, followed by a drop in net load throughout the day and an early evening ramp. The graphic also shows the CAISO gross and net load on the gross peak day in 2023. On that day, as solar generation waned in the late afternoon, demand was only slowly declining. As a result, the net peak occurred roughly three hours after the gross peak. The net peak on this day was the 2nd highest in 2023. When examining other days within the summer, a similar pattern is revealed. The net peak typically occurs 1 to 3 hours after the gross peak.

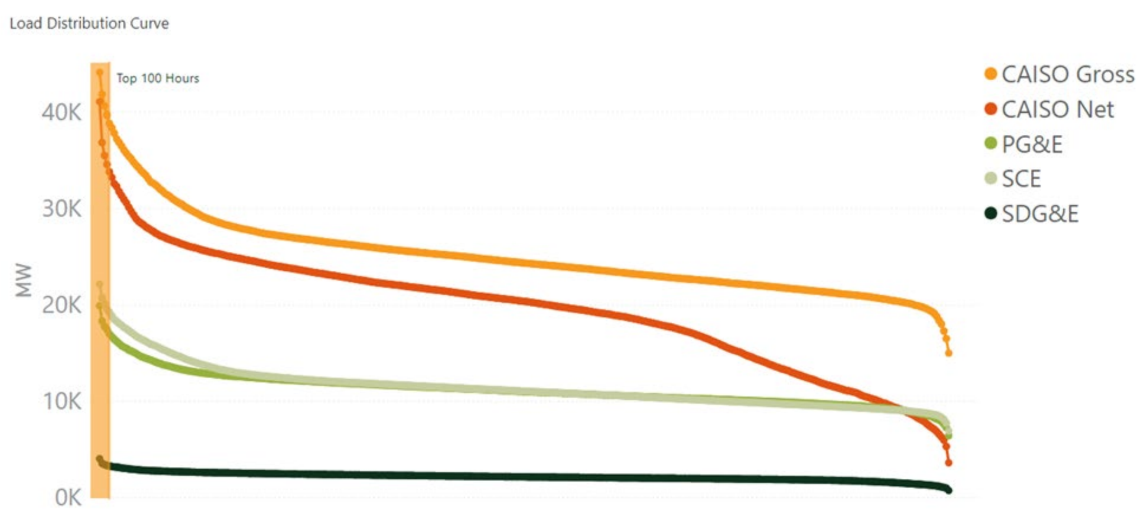
[41] The gross load is equal to total load at the transmission level and is equal to (net) customer meter data plus losses. Gross load therefore includes the impact of customer-sited generation and batteries; it comprises the back of the duck in CAISO's famous duck curve. Net load subtracts grid-scale solar and wind generation and comprises the belly of the duck. While gross load is the amount that must be generated or imported to meet customer demand, the net load is a better indicator of both energy prices and grid stress than gross load.

FIGURE 4-97: CAISO GROSS AND NET LOAD FOR AVERAGE SUMMER DAY VS CAISO PEAK DAY (08/16/2023)



CAISO and IOU annual peak and net peak hour coincident generation is a snapshot of beneficial program impacts. Analyzing the top 100 peak hours results in a more robust measure of impacts during CAISO and IOU peak grid loads. Representing just 1.1% of all the hours in a year, the top 100 peak hours capture the steepest part of load distribution curves. Figure 4-98 shows the 2023 CAISO and IOU load distribution curves and indicates the 100-hour mark as the solid orange bar on the left side.

FIGURE 4-98: LOAD DISTRIBUTION CURVES



The distributions of the top 100 hours over a year differ between CAISO and the three IOUs, and from year to year. While generally mid-to-late summer afternoon occurrences, a top 100 hour can occur as early as June, but during 2023, most of these hours occurred during August and September. Figure 4-99 displays the distribution of the top 100 peak hours by month. The majority of the top 100 hours occurred in July and August across all utilities. In 2023, PG&E saw the earliest peak hours occurring in June.

FIGURE 4-99: TOP 100 HOUR DISTRIBUTIONS BY MONTH

Top 100 Hour Distributions by Month

Year	June	July	August	September	October
2023					
CAISO Gross		51	49		
CAISO Net		38	51	6	5
PG&E	4	50	46		
SCE		54	44	2	
SDG&E		30	44	25	1

4.3.1 Energy Storage

As a load shifting technology, BTM storage can provide grid benefits if the timing and magnitude of storage discharge aligns with periods of grid stress and coincident peak demand and system charging is left to less critical times. As detailed above, SGIP nonresidential storage systems are generally being utilized to reduce non-coincident monthly peak demand, but also TOU energy arbitrage. Systems designed for demand charge reductions may incur increases on the energy component of their bill, but demand reduction savings lead to a net decrease in bills overall. We also observe nonresidential systems performing TOU arbitrage exclusively, and subsequent charging leads to increases in non-coincident peak demand.

Residential storage systems are being utilized for TOU arbitrage and self-consumption – where the battery is discharged to minimize grid imports during the on-peak period as well as after. Residential systems are realizing savings on the energy component of their bill, especially during summer months when on-peak and off-peak price differentials are high, and systems are utilized more often.

The timing of charge and discharge not only impacts customer bills, but it can also have an impact on grid services. Benefits to these systems are potentially due to participation in demand response programs (both system-level/localized and real-time/day-ahead), enrollment in IOU tariffs with TOU rates or peak energy pricing like Critical Peak Pricing (CPP) or Peak Day Pricing (PDP). Some benefits may just be coincidental. Storage project operators and host customers may not be aware of system or utility level peak hours unless they are enrolled in a demand response program or retail rate where a price signal (or incentive) is generated to shift or reduce demand. Customers understand their facility operations and bill rate structure, but grid level demand may not be in their purview.

Storage discharge behavior that is coincident to critical system hours can provide additional benefits beyond customer-specific ones. These benefits include avoided generation capacity costs and transmission and distribution costs. The evaluation team assessed this potential benefit by quantifying the storage dispatch from the sample of nonresidential and residential systems during the top 100 gross and net peak demand hours in 2023 for the CAISO system, along with IOU-specific peaks.

CAISO System Impacts

Verdant examined how SGIP storage systems were operating during periods when the grid may be capacity constrained. We analyzed the magnitude of residential and nonresidential storage system charge and discharge during some of the peak system-level hours. To evaluate CAISO system-level impacts, we reviewed both the top gross and net load hours in 2023. On any given day, CAISO load is comprised of a variety of energy supply sources, including natural gas power plants, large hydro, imported power and grid-level renewables like wind and solar. The availability of renewable energy throughout the day allows grid operators to use less fossil fuel-based sources. However, the intermittent nature of these renewables is disruptive. The correct timing of energy storage discharge and charge can help ease that transition and alleviate that disruption.

Intermittency is particularly troublesome with grid-scale solar PV which, like on-site rooftop solar, generates only when the sun is shining. Billed on-peak periods, like from 4 pm – 9 pm, provide price signals to customers to reduce, avoid, or shift their consumption during those periods, but that five-hour period is still broad. Most residential systems are two-to-three-hour batteries, so if a system fully discharges during the early on-peak period (4 pm to 6 pm), state-of-charge will be insufficient to continue discharging throughout the latter hours of the on-peak period. Discharging a few hours later at full capacity or over a longer duration could provide more utility benefits and GHG reductions – as grid-level net load ramps – with bill savings largely unchanged. CAISO gross load (including renewables) peaked on 8/16/2023 between the 5pm and 6pm hour, while the net peak occurred a day early, and over two hours later. As a result, we examined storage performance at two peak periods: the gross peak, when overall demand is at its highest and all available electricity supply sources reach their maximum generation (MW), and the net peak, when overall demand minus renewable supply sources is reaching peak generation.

For each customer sector, we evaluated the average kWh discharge per kW capacity during all CAISO gross and net hours in 2023. Figure 4-100 and Figure 4-101 present those results for the nonresidential sector. On the vertical axis is the average discharge (+) and charge (-) kWh normalized by kW capacity. The secondary vertical axis provides the average hourly CAISO MW load, and the horizontal axis ranks the gross and net CAISO hours from highest to lowest throughout the year. While it’s difficult to tease out individual hourly impacts from a figure exhibiting 8,760 of them, general patterns are observable. Greater average hourly discharge occurs during higher ranked CAISO gross and net hours compared to lower load hours. This behavior supports the distributions of discharge by time of day presented in Section 4.2.1 where a combination of TOU arbitrage and demand charge reductions were observed across the fleet of nonresidential storage systems. Greater magnitudes of charging occur during the lowest Net CAISO peak hours because that load represents hours when grid-scale renewables like solar PV are generating a significant mix of California's energy portfolio – times when nonresidential systems paired with on-site PV are also charging.

FIGURE 4-100: HOURLY STORAGE KWH PER KW – 2023 CAISO GROSS LOAD HOURS FOR NONRESIDENTIAL

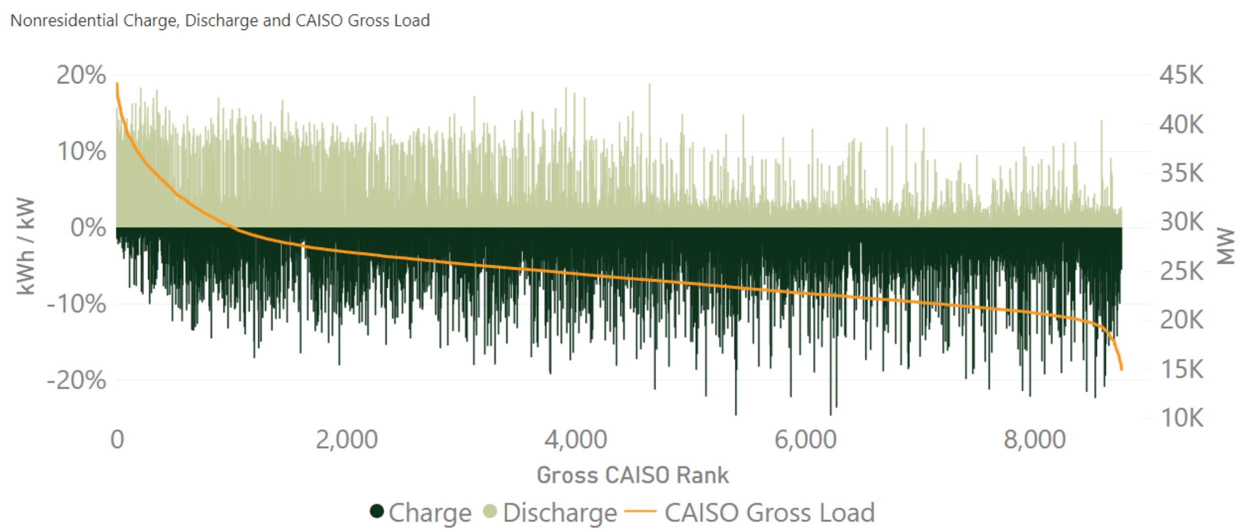
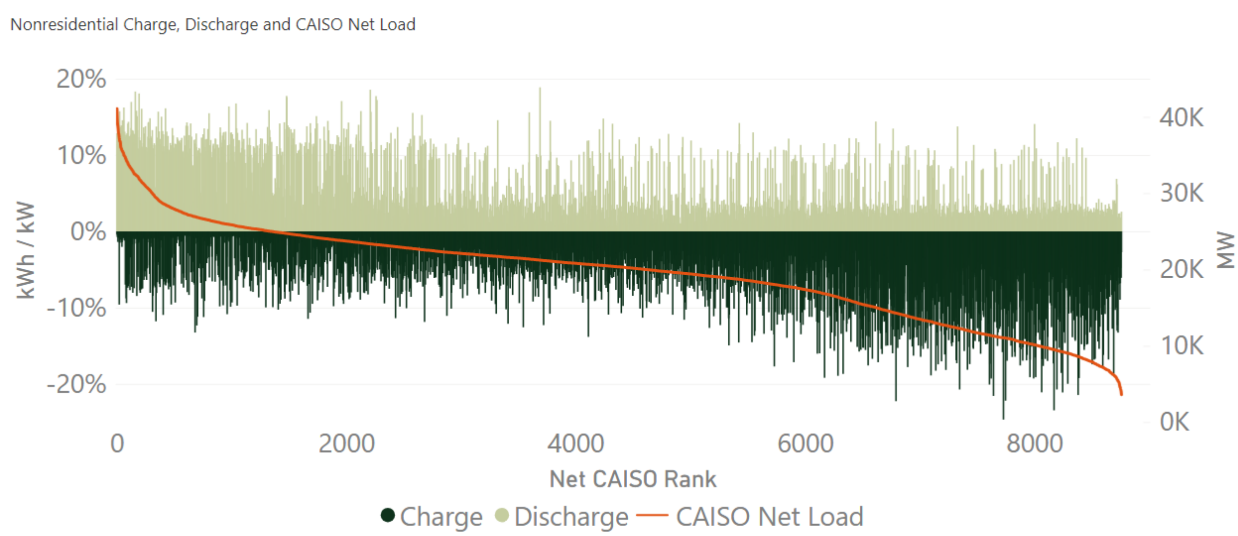


FIGURE 4-101: HOURLY STORAGE KWH PER KW – 2023 CAISO NET HOURS FOR NONRESIDENTIAL



Residential systems exhibit a similar trend in average hourly charge and discharge during ranked gross CAISO hours – greater discharge magnitudes during peak hours relative to lower demand hours, but still significant inter-hour charging and discharging during the year. More evident is the negative correlation between discharge and charge magnitudes when compared against net CAISO hours (Figure 4-103). We observe greater magnitudes of inter-hour discharge than charge during peak net CAISO hours – when residential systems are almost exclusively discharging for self-consumption or arbitrage – and greater inter-hour charging when CAISO net loads are lower – when residential systems are charging systems from on-site PV.

FIGURE 4-102: HOURLY STORAGE KWH PER KW – 2023 CAISO GROSS LOAD HOURS FOR RESIDENTIAL

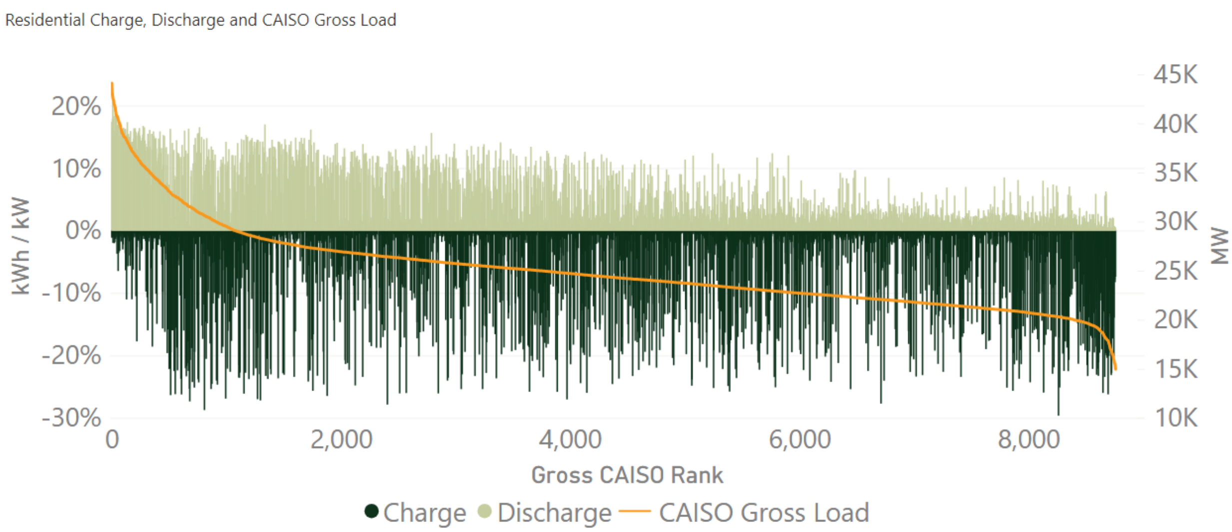
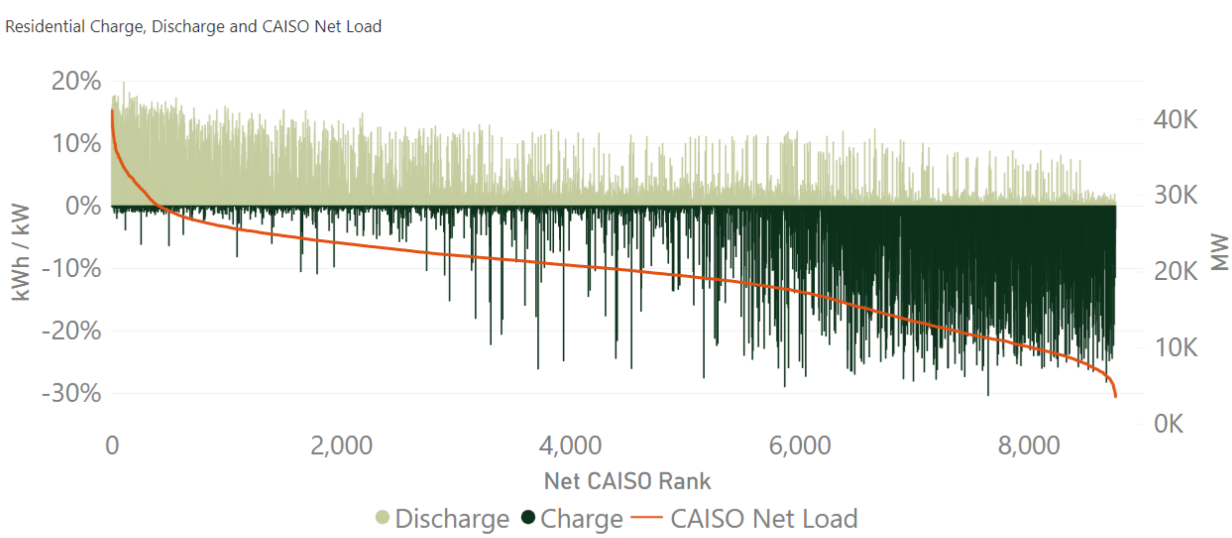


FIGURE 4-103: HOURLY STORAGE KWH PER KW – 2023 CAISO NET HOURS FOR RESIDENTIAL



What follows is the observed performance of SGIP incentivized systems either during the Top 100 CAISO net and gross load hours (most of which occurred August of 2023) or performance based on different system and customer characteristics.

Figure 4-104 and Figure 4-105 below present the average kWh discharge and charge per kW capacity for nonresidential systems during each of the top 100 CAISO gross and net hours in 2023, respectively. Given some of the observed performance differences for standalone and PV paired systems, figures have been further segmented by that classification. Both figures show nonresidential systems actively discharging or charging during all gross and net peak hours at differing magnitudes. When the magnitude of hourly charge is greater than the hourly discharge, then the net discharge is negative. This would signify that, on average, the fleet of nonresidential systems is charging during that hour (and vice versa). As mentioned previously, net peak hours occur later in the day than top gross peak hours during summer months. Some of those later hours correspond to periods when nonresidential systems have already charged from paired PV earlier in the day and are discharging exclusively on peak. This is one of the reasons why charging magnitudes are much lower across top net peak hours for systems paired with PV. Also evident is the greater discharge observed with standalone nonresidential systems, relative to charge during the same hours.

FIGURE 4-104: HOURLY STORAGE KWH PER KW – CAISO TOP GROSS 100 HOURS FOR NONRESIDENTIAL

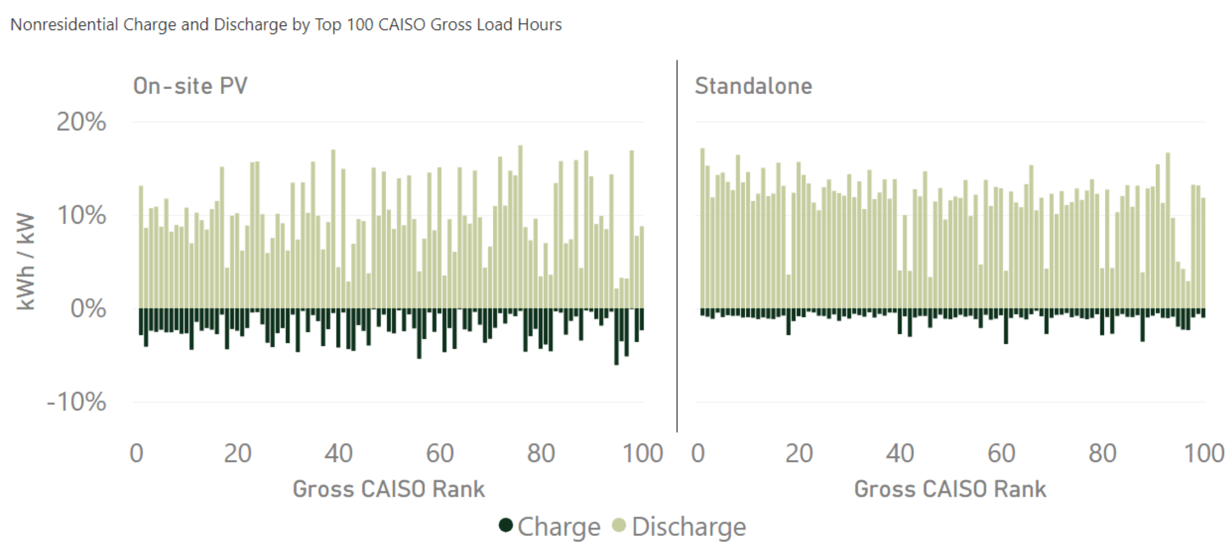


FIGURE 4-105: HOURLY STORAGE KWH PER KW – CAISO TOP NET 100 HOURS FOR NONRESIDENTIAL

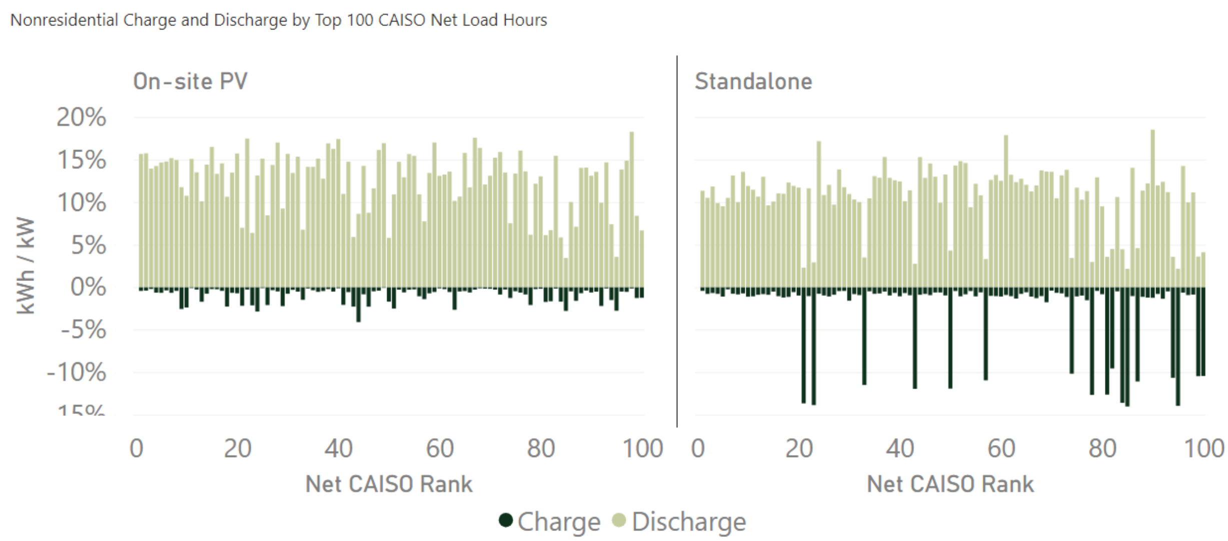


Figure 4-106 and Figure 4-107 present average hourly charge and discharge during peak hours for the residential sector, across all sampled projects. Standalone residential systems are conducting self-consumption or energy arbitrage, so we expect to observe discharging during on-peak net and gross CAISO hours. Standalone system charging occurs almost exclusively after 9 pm and overnight. Some CAISO gross peak hours occur early enough in the day when on-site PV is still generating. Net peaks hours occur later, when both grid-scale and on-site PV generation diminish, and systems begin discharging more regularly to lower or negate on-peak customer load.

FIGURE 4-106: HOURLY STORAGE KWH PER KW – CAISO TOP GROSS 100 HOURS FOR RESIDENTIAL

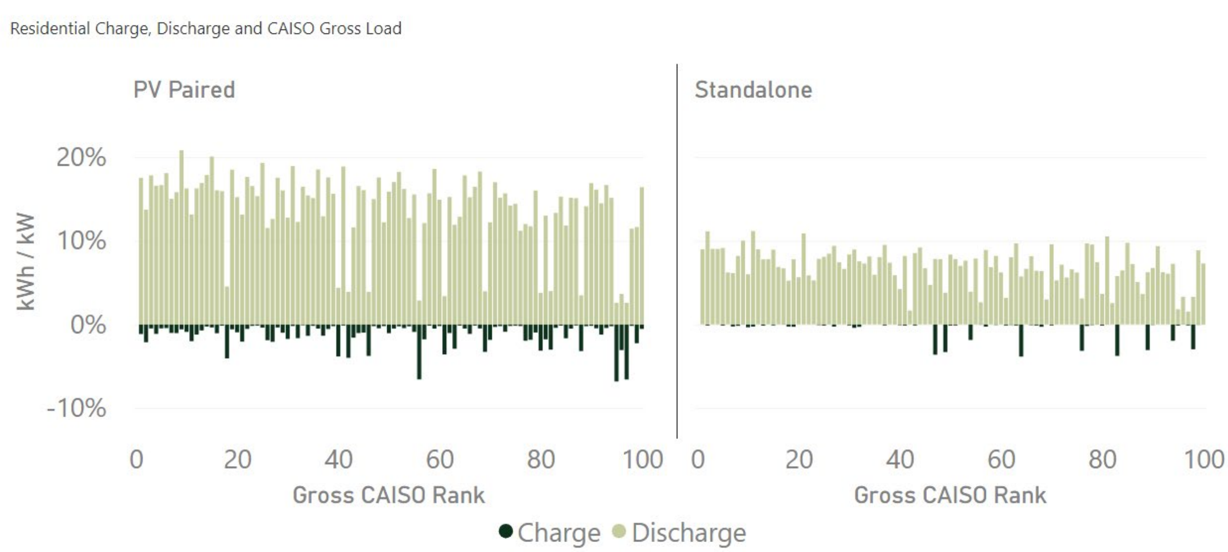
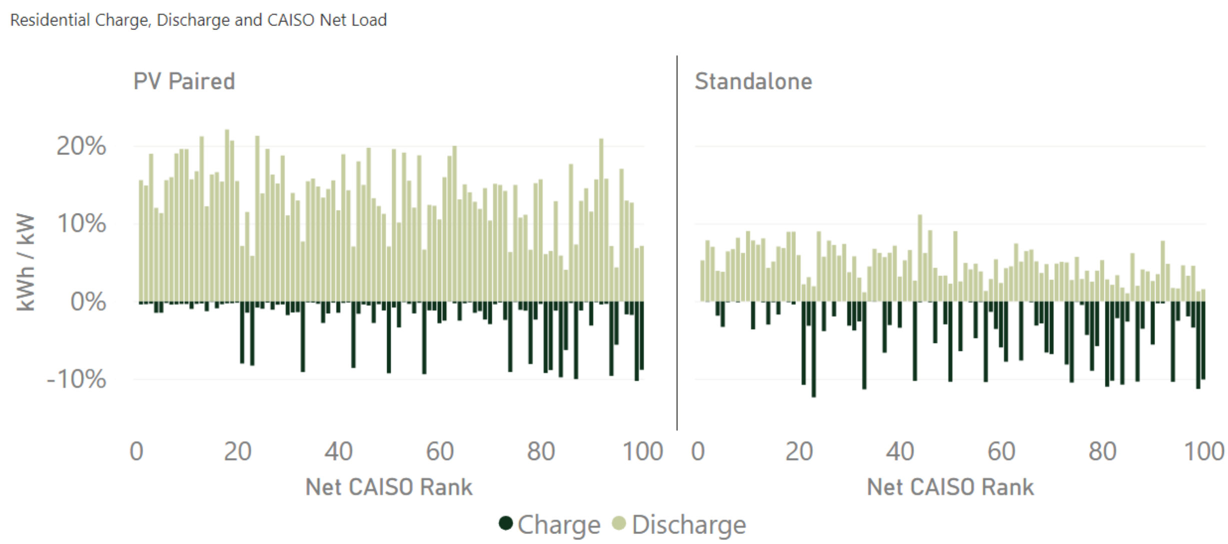


FIGURE 4-107: HOURLY STORAGE KWH PER KW – CAISO TOP NET 100 HOURS FOR RESIDENTIAL



The variability in discharged energy capacity across different time periods and across customer sectors is predicated on the presence of on-site solar generation, underlying load shapes, battery operating modes, and general system utilization. The overall pattern of charge and discharge during top CAISO hours – and during the summer, in general – follows a similar pattern to what has been observed in previous evaluations. However, the magnitude of impacts during top hours continues to evolve from one evaluation to the next. This is due, in part, to peak CAISO hours differing from year to year as well as the underlying load shapes and use cases of customers in SGIP changing from one year to the next. Two of the more critical recent changes are 1) more focused nonresidential discharging during on-peak hours – particularly with medium duration batteries installed via the Equity Resiliency Budget (ERB) category, and 2) residential systems discharging a greater percentage of capacity during the latter half of the on-peak period. Increased price differential between billed on and off-peak, demand response participation like ELRP, and developer fleet dispatch modifications[42] have contributed to more significant benefits realized from the grid perspective.

As discussed in Section 4.2.1, we observe energy storage systems with different operating modes and overall system capacities. Furthermore, some developers not only meter the battery, but also meter PV

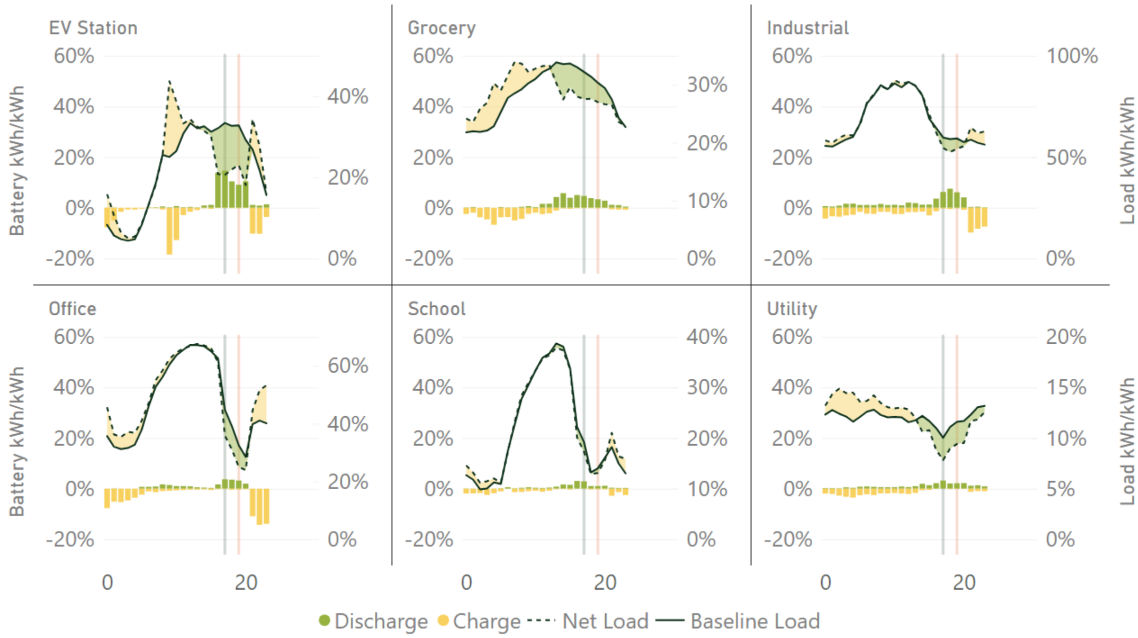
42 In previous evaluations, Verdant observed the fleet of systems for one developer discharging consistently at 4-5 pm during the summer on-peak period. Beginning in the late summer of 2021 they changed the algorithm of discharge and withheld dispatch from the first two hours of the on-peak period and began discharging during 6-7 pm. This grid-friendly behavior was observed during 2023 as well.

production and customer net load. These metering techniques allow the battery to recognize when net load goes positive or negative and provide an opportunity for a customer to conduct self-consumption.

We examine this variability by providing a snapshot of how storage was being dispatched for nonresidential and residential customers on 8/15/2023, the day CAISO experienced the net peak hour. These data are presented below in Figure 4-108 and Figure 4-109. For all figures, the CAISO gross peak hour is highlighted by the leftmost vertical line and the net peak hour follows two hours later (the red vertical line). Baseline and observed net loads are provided, along with the average hourly charge (yellow bars) and discharge (green bars) in kWh normalized by system capacity. The figures also differentiate energy storage system performance by prominent building types and presence of on-site PV or standalone, respectively. Evident for most building types is the greater magnitude of discharge around and within those peak hours (the green shaded area represents a reduction in load compared to the baseline of no storage), despite differences in underlying customer load shapes and magnitudes of peak load. The yellow shaded area represents an increase in load from storage charging.

FIGURE 4-108: NONRESIDENTIAL STORAGE WITH PV UTILIZATION DURING PEAK DAY (BY BUILDING TYPE)

FIGURE 4-109: NONRESIDENTIAL STANDALONE STORAGE UTILIZATION DURING PEAK DAY (BY BUILDING TYPE)



Residential systems paired with PV and standalone systems are discharging during and between gross and net peak hours, with the greatest magnitude of discharge occurring between 5pm and 8 pm. Charging occurs almost exclusively during solar generating hours for PV paired systems. Figure 4-110 illustrates how customer load is impacted by energy storage dispatch on the peak day for PV paired systems and standalone systems. Figure 4-111 presents storage dispatch and load shapes for each of the prevalent operating modes (along with an overall average daily shape).

FIGURE 4-110: RESIDENTIAL HOURLY CHARGE AND DISCHARGE DURING PEAK CAISO NET DAY

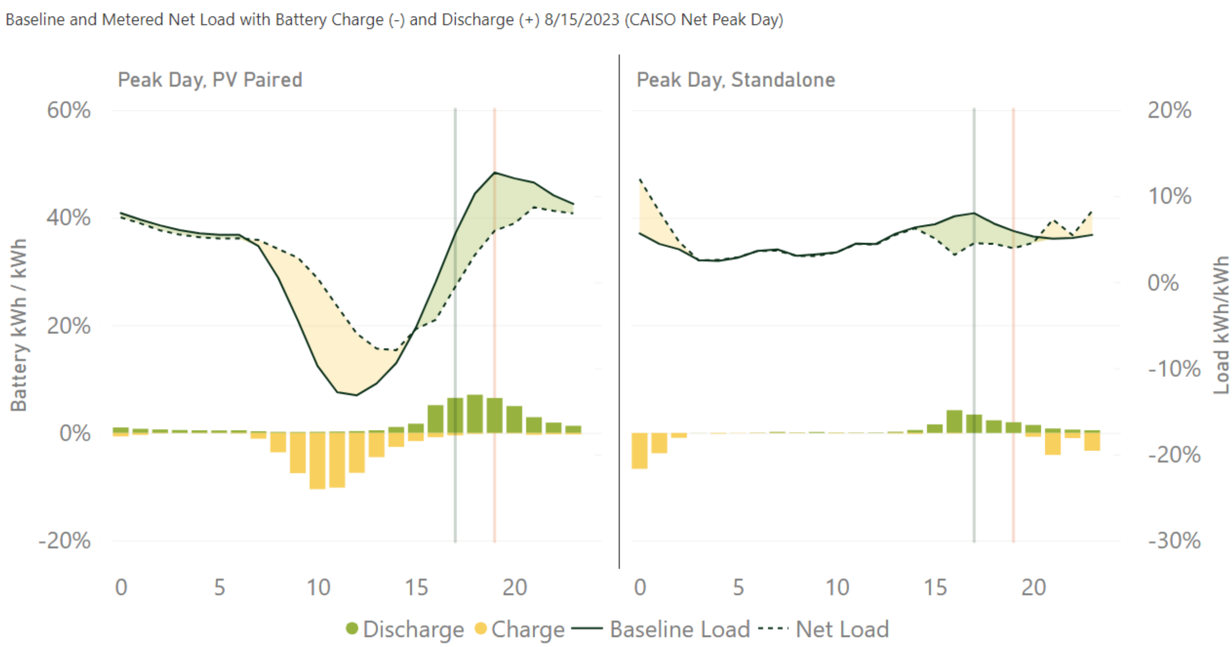
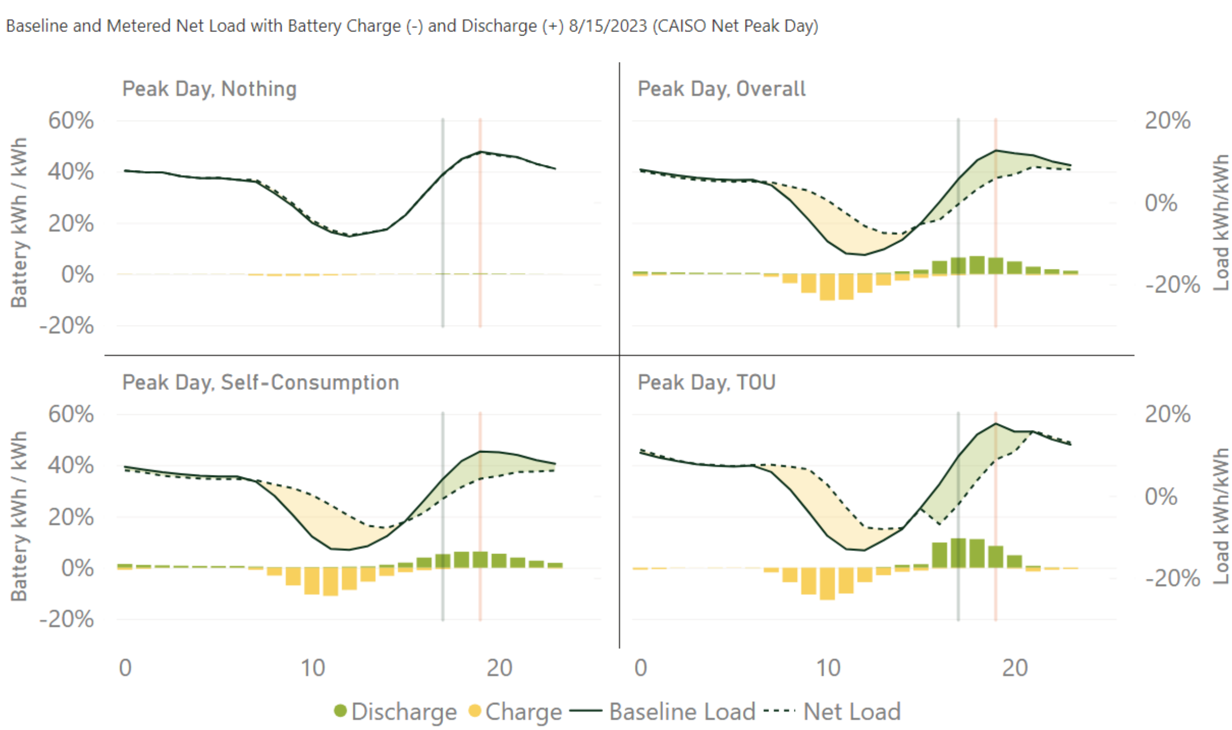


FIGURE 4-111: RESIDENTIAL HOURLY CHARGE AND DISCHARGE DURING PEAK CAISO NET DAY



Residential Storage Utilization during Demand Response Events

The previous section highlighted SGIP energy storage performance during CAISO peak hours. However, the operating modes guiding that performance during critical hours – self-consumption, arbitrage, arbitrage with export – were observed outside these peak hours in 2023. PV paired systems were generally charging during lower grid constrained hours and both paired and standalone systems were discharging in the early afternoon and evening during high utility cost hours and system peaks, particularly in summer months. In other words, on average SGIP energy storage systems were not performing very differently during capacity constrained hours than they were ordinarily in 2023. However, when looking at a subset of ELRP participants on event days, we do see some differences in battery discharge during capacity constrained hours.

Verdant compared average daily residential energy storage performance to system utilization during Emergency Load Reduction Program[43] (ELRP) events for customers participating in the program. Storage systems are generally self-consuming or following a price signal built into a customer billed on- and off-peak rate schedule, so behavioral changes from typical summer weekdays and event days would be either wholly coincidental or predicated on additional signals to customers – flex alert notifications and/or demand response participation where, in the case of ELRP, load reductions can be compensated at up to $2.00 per kWh.

We do observe some incremental utilization and differing performance from systems enrolled in demand response programs like ELRP. During event days, which in 2023 align with capacity constrained grid hours, systems that were ordinarily arbitraging or self-consuming – but were enrolled in ELRP – were discharging more capacity during event windows than ordinarily. In fact, systems were discharging beyond customer load needs and exporting excess capacity to the grid during events. To better understand and quantify any potential incremental performance benefits ascribed to storage during demand response events relative to normal observed dispatch, Verdant compared event utilization to like day utilization.

The methods used to classify similar days included mapping weekday weather station information – like minimum/maximum temperature, mean temperature, and temperature during peak hours – to SGIP storage systems by premise-level zip codes. Comparison or control days were then selected using Mahalanobis distance matching, based on a combination of metrics. After reviewing outputs for each set of selected metrics, Verdant chose the smallest Mahalanobis distance using maximum temperature. This

[43] More information about ELRP can be found here: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/emergency-load-reduction-program-data-and-information

method selected the best fitting temperature shape during the peak hours. Occasionally, the selected day was missing system discharge, load, or PV data, and the second closest Mahalanobis distance was selected. If that day contained missing data, the project was removed from the analysis dataset.

It's important to note that this exercise was not intended to replicate a load impact study. The research question stems from what potential demand reductions a BTM distributed energy resource like energy storage can reasonably provide for quickly dispatchable grid support (there are over 1,700 MWh of installed capacity within the SGIP alone). The question is what percentage of that capacity is already being dispatched for customer TOU arbitrage or self-consumption versus what incremental capacity can be expected from these systems in response to ELRP events. The analysis compared 1) energy storage utilization – charge (-) and discharge (+), 2) customer net load, 3) on-site PV generation, and 4) BTM household consumption on ELRP event days to control days.

Overall, SGIP energy storage systems were not performing that differently during capacity constrained hours than they were ordinarily in 2023, except when looking at the subset of ELRP participants on event days. ELRP participants discharged a greater magnitude of system capacity during events. Moreover, discharge extended beyond customer load requirements, with excess capacity being exported to the grid.

Verdant received 2023 residential ELRP participant lists from PG&E and SDG&E. Residential ELRP participation is around 9 percent of PG&E and SDG&E SGIP participants and was 8 percent of the PG&E and SDG&E SGIP sample. The analysis summarizes 106 PG&E and SDG&E residential ELRP participants that were in the 2023 SGIP sample. There were 7 ELRP events in 2023 between July 20th and September 19th. These events lasted, on average, 3 hours and ranged between 1 and 5 hours. ELRP events in 2023 started between 4pm and 8pm and always ended at 9pm.

Figure 4-112 compares average hourly charge and discharge during ELRP events for customers participating in the program, along with how those systems were operating on similar non-event days. Load shapes – like PV generation, baseline load and behind-the-meter consumption – are all similar across days. However, the dashed line, which represents the metered customer load, is visibly different. More targeted and greater energy storage discharge utilization on event days decrease load to export (green shaded area). Peak event discharge reaches roughly 14% of system kWh capacity during the 7pm hour on event days. On non-event days, peak discharge reaches 6% of capacity during the 6pm hour.

FIGURE 4-112: AVERAGE RESIDENTIAL LOAD SHAPES DURING ELRP EVENTS AND CONTROL DAYS

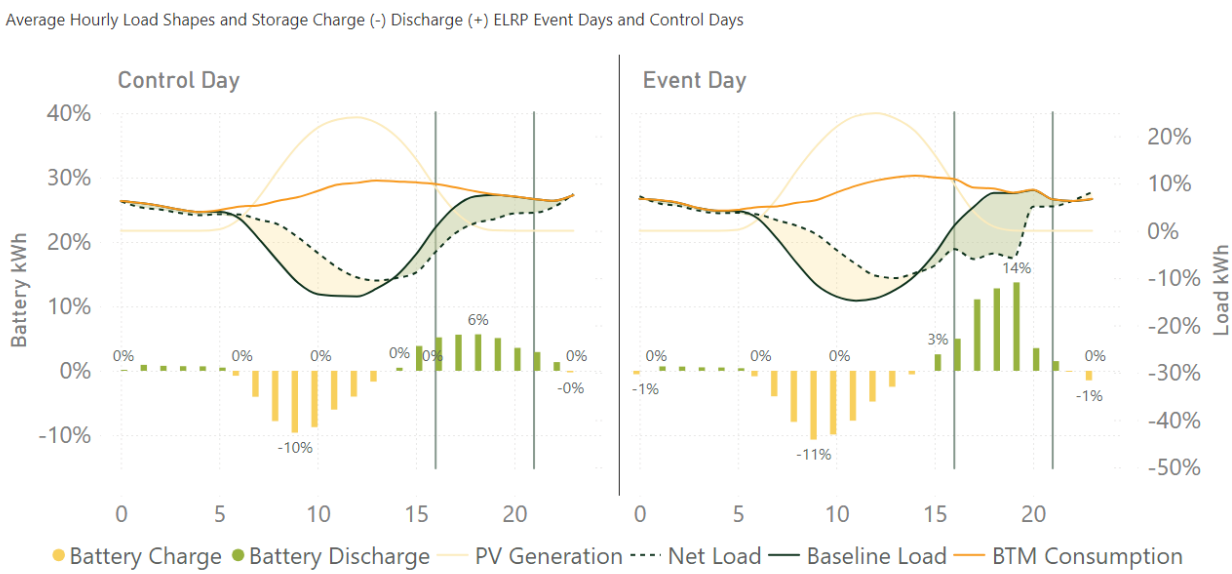
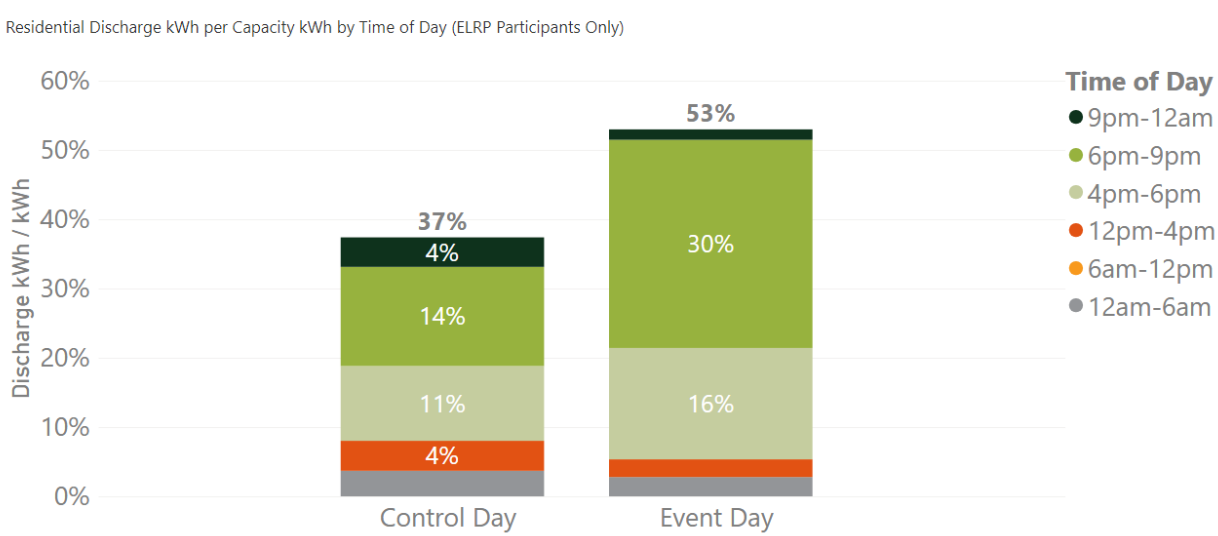


Figure 4-113 summarizes the average daily discharge for systems participating in ELRP. Control day utilization averages 37% of kWh capacity with a majority being dispatched between 4pm and 9pm. On event days, daily utilization increases to roughly 53% of capacity. Discharge magnitudes during the 4pm-9m peak almost double on these days. Not only were ELRP participants discharging a greater magnitude of system capacity during events, but discharge also extended beyond customer load requirements, with excess capacity being exported to the grid.

FIGURE 4-113: AVERAGE DAILY RESIDENTIAL DISCHARGE PER KWH CAPACITY (ELRP VERSUS CONTROL DAYS)



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4.3.2 Generation

Unlike energy storage, generation technologies are not typically used for load shifting or TOU arbitrage but are mostly used to satisfy a customer's base load. Therefore, while they can provide peak hour benefits, these benefits are not typically greater than will be seen the rest of the year. Generation coincident with the gross and net CAISO annual peak hours during 2023 (i.e., the impact in terms of reducing the gross or net load peak) is shown by PA in Table 4-4. PG&E projects contributed the largest portions of the gross CAISO peak hour generation, making up over 40% of the total generation during the CAISO gross and CAISO net peak hours of 2023.

TABLE 4-4: ANNUAL OBSERVED CAISO GROSS AND NET PEAK DEMAND IMPACT BY PROGRAM ADMINISTRATOR

CAISO	PA	Peak Hour Generation [MW]	Percent of Total
Gross	CSE	11.59	8.8%
	PG&E	56.50	42.7%
	SCE	31.30	23.6%
	SoCalGas	33.04	25.0%
	Total	**132.44**	**100%**
Net	CSE	8.92	7.3%
	PG&E	50.32	41.2%
	SCE	31.16	25.5%
	SoCalGas	31.79	26.0%
	Total	**122.19**	**100%**

Figure 4-114Figure and Figure 4-115 show the CAISO gross peak demand impact per rebated capacity kW, by technology type total, as well as broken out by PA. Gas turbines generated the highest peak demand impact per rebated kW during 2023 during the statewide gross peak, followed by CHP fuel cells and microturbines in 2023, statewide. When comparing by PA, gas turbines, fuel cells, and internal combustion engines typically saw the highest peak demand impact per rebated kW.

FIGURE 4-114: 2023 OBSERVED CAISO GROSS PEAK DEMAND IMPACT BY EQUIPMENT TYPE

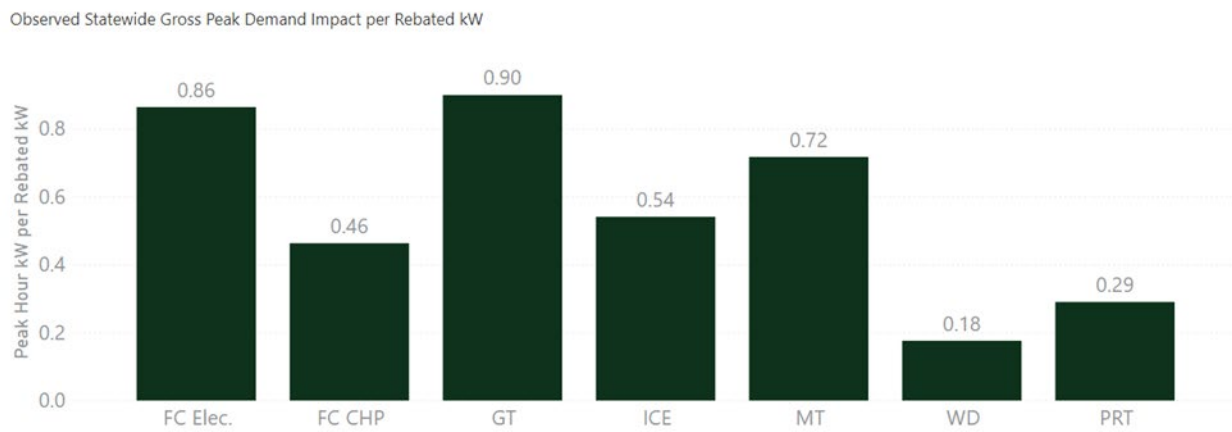
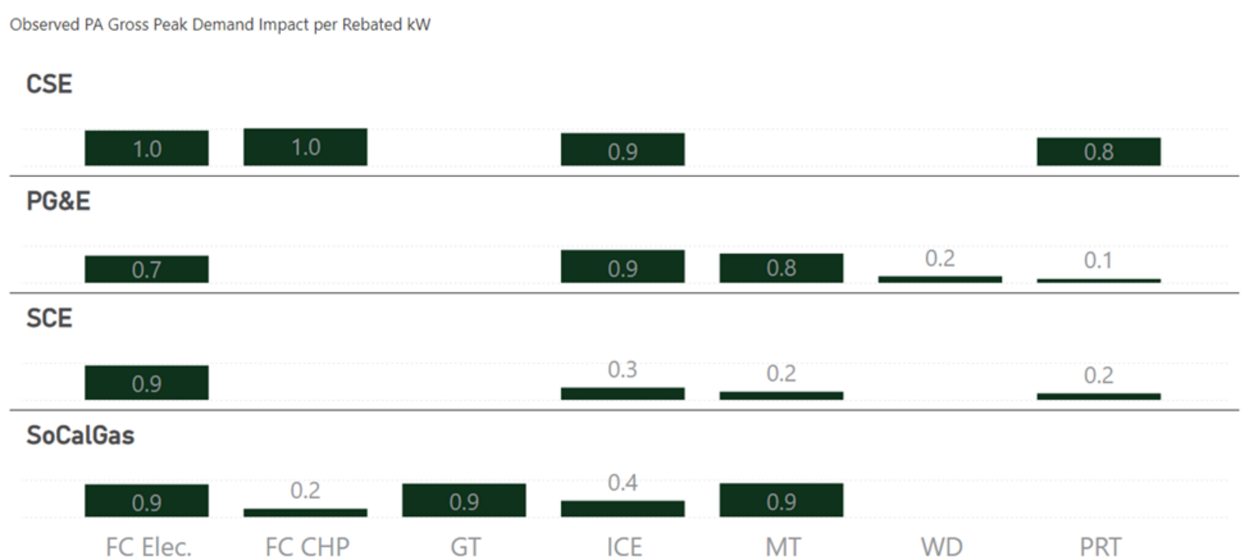


FIGURE 4-115: 2023 OBSERVED CAISO GROSS PEAK DEMAND IMPACT BY EQUIPMENT TYPE AND PA



Gross peak IOU impacts were also analyzed, as displayed in Figure 4-116. These peak hour impacts from SGIP systems are assigned to the IOU providing the electrical service, which is not necessarily the same as the PA. For example, SoCalGas projects may be electrically interconnected to a municipal utility rather than an IOU.

The 2023 PG&E gross peak hour generation occurred on August 15th, between 6-7 PM local time. During this hour, observed projects electrically interconnected to PG&E's system generated 0.4 kW per rebated kW. SCE's 2023 gross peak hour was on July 26th between 4 and 5 PM, where coincident generation from observed projects was 0.9 MW per rebated kW. Observed projects interconnected to SDG&E's electrical system reached 0.7 MW per rebated kW during the 2023 gross peak hour on August 29th between the hours of 6 and 7 PM.[44] Similar to the CAISO findings, on a per rebated kW basis, observed CAISO peak hour generation per kW was generally led by fuel cells, gas turbines, and internal combustion engines.

FIGURE 4-116: ANNUAL IOU GROSS PEAK DEMAND IMPACT BY EQUIPMENT TYPE AND ELECTRIC UTILITY

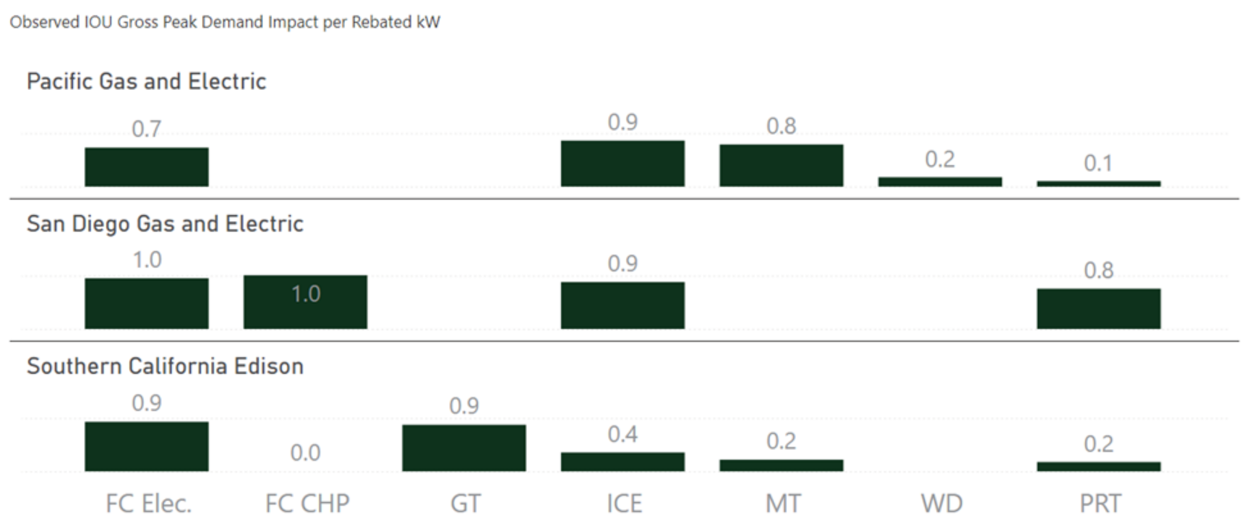


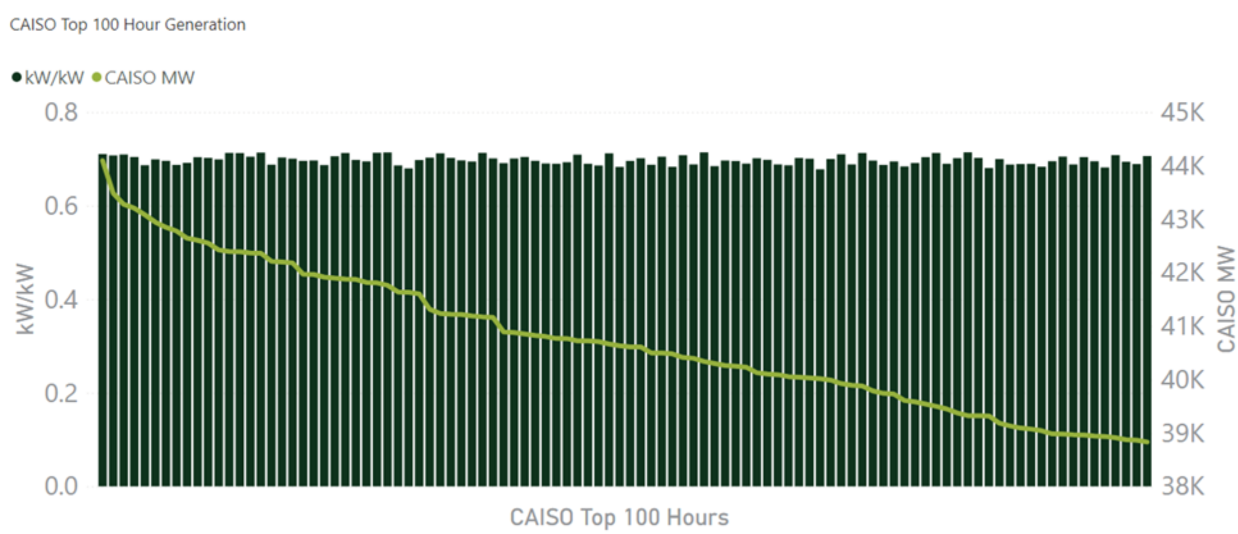
Figure 4-117 shows observed project generation per rebated kW coincident with the three IOU and CAISO gross and net peak hours, alongside average project generation per rebated kW coincident with the top 100 peak hour. On a per rebated kW basis, peak hour generation and top 100-hour average generation were very close in all cases.

44 The defined peak hours are all in local time.

FIGURE 4-117: OBSERVED PEAK HOUR GENERATION COMPARED TO AVERAGE TOP 100 HOUR GENERATION [PER KW]

As discussed above, generation systems typically provide a baseload, rather than providing peak hour benefits. Figure 4-118 below highlights the observed generation per rebated kW over the CAISO top 100 hours, showing that the generation per rebated kW generally stays steady across the top 100 hours.

FIGURE 4-118: OBSERVED CAISO GROSS TOP 100 HOUR GENERATION PER REBATED CAPACITY KW



4.4 ENVIRONMENTAL IMPACTS

The environmental impact considered in this analysis is change in emissions of the GHG CO_2, as CO_2 is the

GHG most affected by the operation of SGIP systems.[45] Environmental impacts are calculated as the difference between the CO_2 emissions associated with SGIP system operations and those associated with counterfactual baseline system operations. In the case of generation systems, numerous possible baseline conditions are possible depending on the type of fuel being utilized by the SGIP system. When the baseline entails venting of methane directly to the atmosphere the GHG impact is expressed in terms of equivalent CO_2 (CO_2eq). Details of GHG impact calculations for generation systems are provided as Appendix D. Generation systems and energy storage systems both change the timing and magnitude of CO_2 emissions of electric utilities. This aspect of the environmental impacts analysis is described below.

The relationship between electric grid load and marginal CO_2 emissions is depicted graphically in Figure 4-119. Two days in 2023 are presented; 1) 4/30/2023 – a sunny, Sunday in late April on the left, 2) 8/15/2023 – on the right, where CAISO Net Load reached its 2023 peak during the 7pm hour local time. The orange and red lines represent hourly CAISO Gross and Net load, respectively, and the dark bars represent average marginal emissions during that hour. Also highlighted are the 4pm – 9pm hours for each day.

System load and corresponding marginal emissions on the left are typical of a spring day. For many hours during the day where marginal emissions are zero, ample sunshine, long daylight hours, and low demand for energy-intensive end uses like A/C allow grid-scale renewable solar generation to provide all but some base load to satisfy system demand – and even after exporting to other states, some of the grid-scale renewables must actually be curtailed to keep the grid stable, resulting in zero or even negative prices in the CAISO. Marginal emissions are zero when renewables are being curtailed, because more load will be met by reducing curtailment rather than by increasing GHG-producing generation. During the 4pm and 5pm hours, renewable generation continues to decrease from its mid-day maximum and is displaced by more carbon-intensive generators.

[45] The real-time marginal GHG emissions signal developed by WattTime represents the compliance signal for this evaluation and the SGIP, in general. These data are publicly available here: https://sgipsignal.com/.

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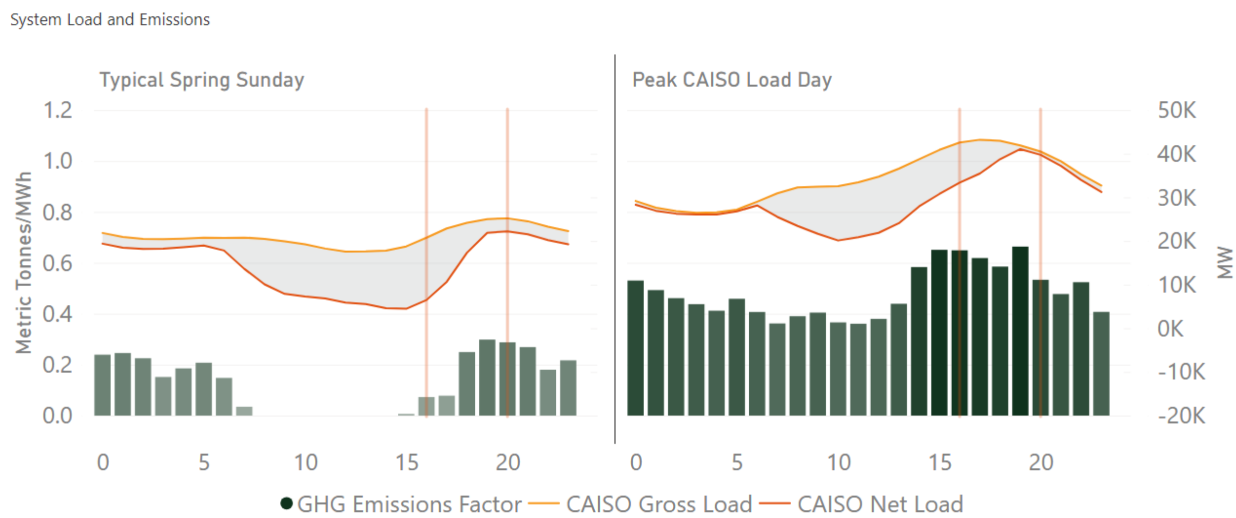
FIGURE 4-119: CAISO LOAD AND MARGINAL EMISSIONS ON SPRING DAY VERSUS PEAK DAY



System load on the peak day (right pane of Figure 4-119) is much greater and marginal emissions don't hit zero at any point during the day (although we observe a drop between 7am – 11am when grid-scale renewables begin to ramp, and underlying system demand is still low). At the net peak (7pm) emissions remain stable where the upper bound of power plant heat rate is reached – signifying the most carbon-intensive generator is operating at the margin throughout those hours. A perfectly designed energy storage system optimized to reduce GHG emissions would charge only during the lowest marginal emissions periods and discharge during (net) peak hours only.

Generation systems, on the other hand, generally provide a baseload to the facility, and don't have significant variation hour to hour or season to season and are therefore not optimized to maximum GHG emissions reductions during peak hours. Renewably fueled systems with vented baselines saw the highest GHG emissions reductions, but non-renewable fueled systems with high heat recovery rates also reduced GHG emissions.

The marginal grid GHG emissions values used to calculate environmental impacts were prepared by WattTime. The data sources and analytic methodology used by WattTime are consistent with the Avoided Cost Calculator (ACC) and are approved by the CPUC. Assumptions in the ACC are updated periodically. Updated assumptions in the 2020 ACC and the 2021 ACC provided motivation for an update to the SGIP GHG Signal calculations. That update resulted in WattTime releasing a new version of the SGIP GHG Signal

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starting February 1, 2022: Version 2.[46]

4.4.1 Energy Storage

Hourly GHG impacts were calculated for each SGIP system as the difference between the grid power plant emissions for observed system operations and the emissions for the baseline condition or the counterfactual. Baseline emissions are those that would have occurred in the absence of the storage system. Facility and household loads are identical for baseline and SGIP conditions. What varies is the timing and quantity of grid power plant electricity required to maintain balance between loads and electrical supply in response to storage charging and discharging.

Hourly storage performance is equal to the charge or discharge that occurred during that interval. The energy impact during that interval is then multiplied by the marginal emissions rate for that interval (kilograms CO_2 / kWh) to arrive at an hourly emissions impact. Emissions generally increase during storage charge and decrease during storage discharge. A system's annual GHG impact is the sum of the total emissions.

Energy storage technologies are not perfectly efficient. Consequently, the amount of energy they discharge over any given period is always less than the amount of energy required to charge the system. Roundtrip efficiency (RTE) losses from AC/DC power conversion and parasitic loads – particularly with under-utilized systems – will always result in increased energy consumption at a customer's home or facility relative to the baseline condition without storage. For energy storage systems to reduce emissions, the emissions *avoided* during storage discharge must be greater than the emission increases during storage charging. In other words, SGIP storage systems must charge during "cleaner" grid hours and discharge during "dirtier" grid hours to achieve GHG reductions. Grid-level renewable generation during morning and early afternoon hours helps satisfy system-level demand throughout those hours. During periods when more renewables are on the grid, marginal GHG emissions tend to reduce as well. As renewable generation wanes in the late afternoon and demand ramps are satisfied on the margin with more imports and natural gas peak generators, marginal emissions tend to increase.

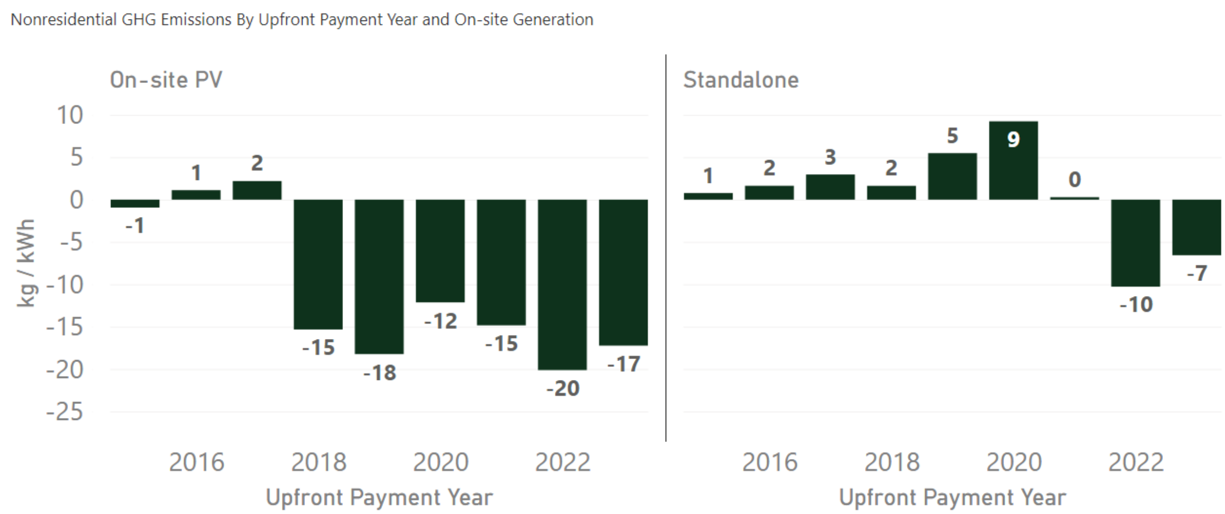
Nonresidential Storage

Figure 4-120 presents the range in GHG emissions reductions (-) or increases (+) for the sample of nonresidential projects analyzed as part of the 2023 Impact Evaluation. The bar chart provides the year in

[46] Presentation: 'SGIP GHG Signal Update', WattTime. Self-Generation Incentive Program Fourth Quarterly Workshop, December 13, 2021. https://www.selfgenca.com/documents/workshops/2021/q4

which an SGIP energy storage project received their upfront incentive payment, along with if the systems are paired or co-located with on-site PV (left pane) or are standalone (right pane). We observe an overall increase in system efficiency and utilization from systems installed more recently, and this behavior helps contribute to many more realized GHG emission benefits. Except for some earlier vintage projects, systems paired with PV – independent of payment year – reduced emissions in 2023, with average reductions (-) ranging from 12 kg/kWh for systems paid in 2020 to as high as 20 kg/kWh for systems paid in 2022. More recent standalone system installations are reducing emissions as well.

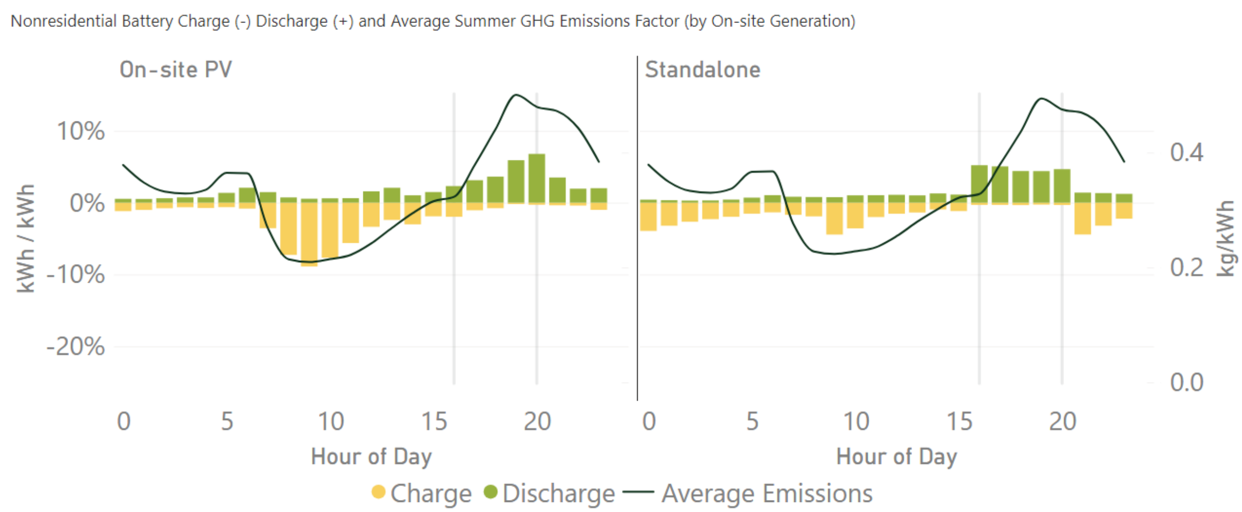
FIGURE 4-120: EMISSIONS (KILOGRAMS GHG/KWH) FOR NONRESIDENTIAL SYSTEMS BY UPFRONT PAYMENT YEAR



Recent reductions in GHG emissions in the nonresidential sector are largely attributable to PV paired storage performance, more targeted on-peak discharge from standalone systems, and more recent installations of longer duration batteries in the ERB conducting arbitrage at the expense of non-coincident peak demand reductions (and subsequent charging “snapback” associated with demand shaving). Figure 4-121 presents average energy storage charge (-) and discharge (+) kWh/kWh capacity along with the average marginal emissions shapes by PV paired or co-located systems operating in summer months of 2023 and standalone systems operating during the same time. The marginal emissions curve (with units displayed on the secondary vertical axis) conveys the hour-by-hour variability in emissions magnitudes. Emissions exhibit a morning ramp when system demand begins, but prior to grid-scale renewable generation. The subsequent dip in emissions thereafter is caused by renewable generation ramping. Summer months are laden with high cooling loads later in the day – represented by the peak from 7 pm to 9 pm.

More importantly than highlighting the marginal emissions in isolation, is the corresponding energy storage performance during those hours. Yellow bars represent charging, and we observe much greater charging from on-site solar for paired systems, which is also coincident to lower marginal emissions periods. Discharging (green bars) is observed during on-peak hours and coincident to high marginal emissions. Standalone systems also discharge during the peak and are "net" charging in all other hours.

FIGURE 4-121: NONRESIDENTIAL SUMMER STORAGE DISPATCH AND MARGINAL EMISSIONS BY ON-SITE GENERATION

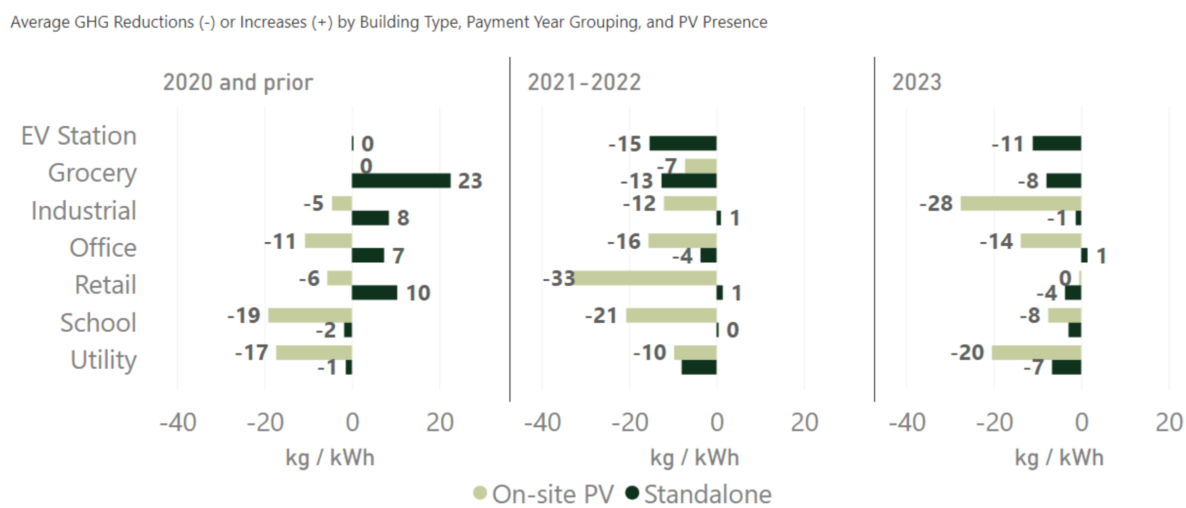


The above figure is an average across the fleet of nonresidential systems and belies some of the more nuanced performance by budget category, facility type, and battery size. In Figure 4-122, Verdant has combined systems paid in 2020 and prior (left) and compared those against systems paid in 2021-2022 and those paid in 2023. Comparisons for each period are made by facility type and presence of on-site PV. Bars moving left from zero represent average reductions in emissions (kg /kWh) for each of the facility types on the left. Bars moving right from the reference line signal increases in emissions. Standalone systems are dark bars, and PV paired systems are presented in light green. For many of the reasons discussed above, PV paired systems are reducing emissions – independent of facility type – with magnitudes of reductions similar across project vintage. The more surprising detail is the standalone emissions reductions – particularly for EV stations and Utility classifications. Systems installed at dedicated EV charging stations are themselves charging exclusively during morning off-peak hours and discharging on-peak, potentially due to high peak to off-peak differentials in EV rates, or driver behavior favoring EV charging (and thus SGIP battery discharging) late in the day. Utility classification represents mostly critical facilities incentivized through the ERB. The most common installations are medium duration (4-6 hour)

Overall, improved performance from legacy systems and favorable behavior from more recent installations have improved nonresidential GHG performance in 2023.

batteries installed at wastewater treatment plants servicing a low-income community. We've already discussed how these systems regularly discharge throughout peak hours and charge overnight (often creating a new facility peak as a result).

FIGURE 4-122: NONRESIDENTIAL STORAGE DISPATCH AND MARGINAL EMISSIONS BY PAYMENT YEAR AND PV



Overall, improved performance from legacy systems and favorable behavior from more recent installations continued to improve nonresidential GHG performance in 2023, relative to past evaluation years. Verdant also re-created average summer[47] weekday marginal emissions and average charge (yellow) and discharge (green) as percentage of system kWh capacity (Figure 4-123 and Figure 4-124 below). Again, standalone system discharge is focused during the summer on-peak period, which is coincident to greater marginal system emissions. PV paired systems exhibit similar discharge profiles, but the greater magnitude of charging from solar and during lower grid-scale marginal emissions leads to greater overall emissions reductions.

[47] Summer refers to June through September inclusive.

FIGURE 4-123: NONRESIDENTIAL SUMMER STORAGE DISPATCH AND MARGINAL EMISSIONS BY ON-SITE GENERATION AND BUILDING TYPE

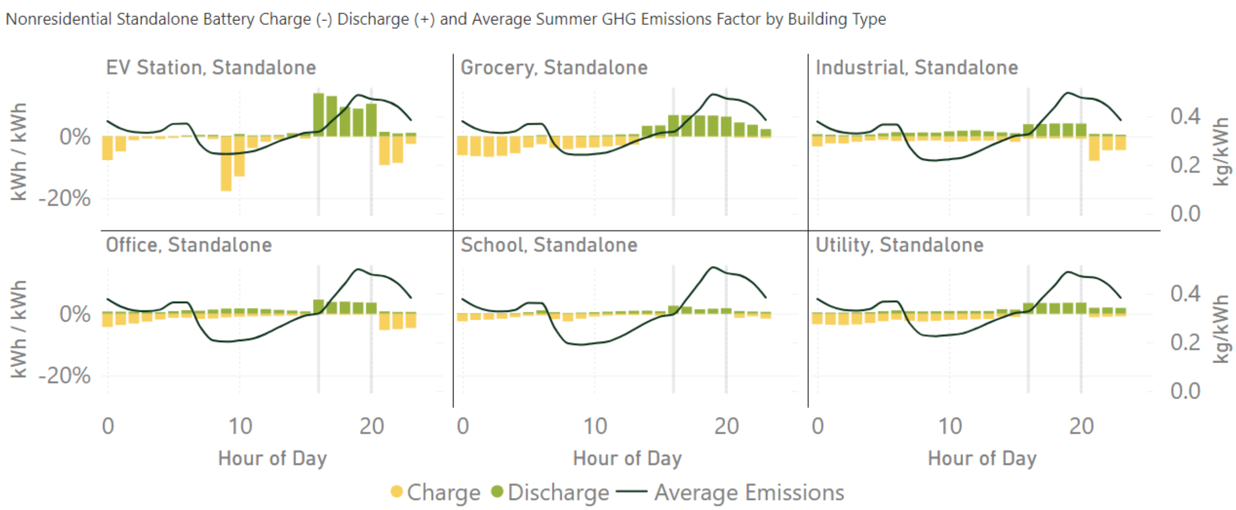


FIGURE 4-124: NONRESIDENTIAL SUMMER STORAGE DISPATCH AND MARGINAL EMISSIONS BY BUILDING TYPE

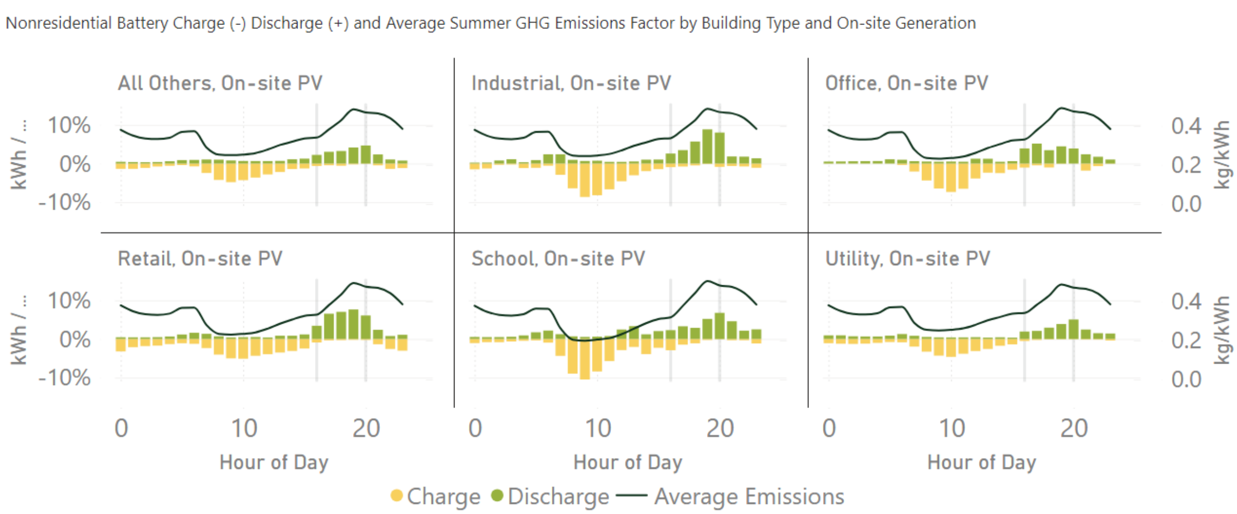


Figure 4-125 through Figure 4-127 present project-specific scatterplots of average emissions increases (+) or reductions (-) and utilization in 2023 for paired versus standalone systems, by budget category, and by building type, respectively.

FIGURE 4-125: NONRESIDENTIAL PROJECT GHG EMISSIONS AND UTILIZATION BY ON-SITE GENERATION

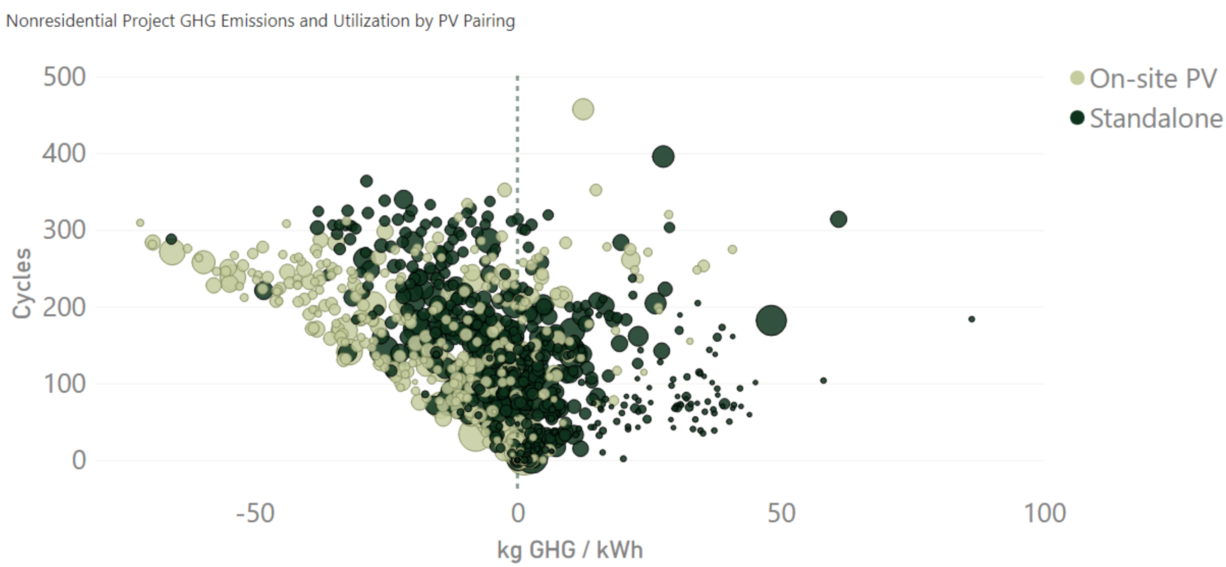


FIGURE 4-126: NONRESIDENTIAL PROJECT GHG EMISSIONS AND UTILIZATION BY BUDGET CATEGORY

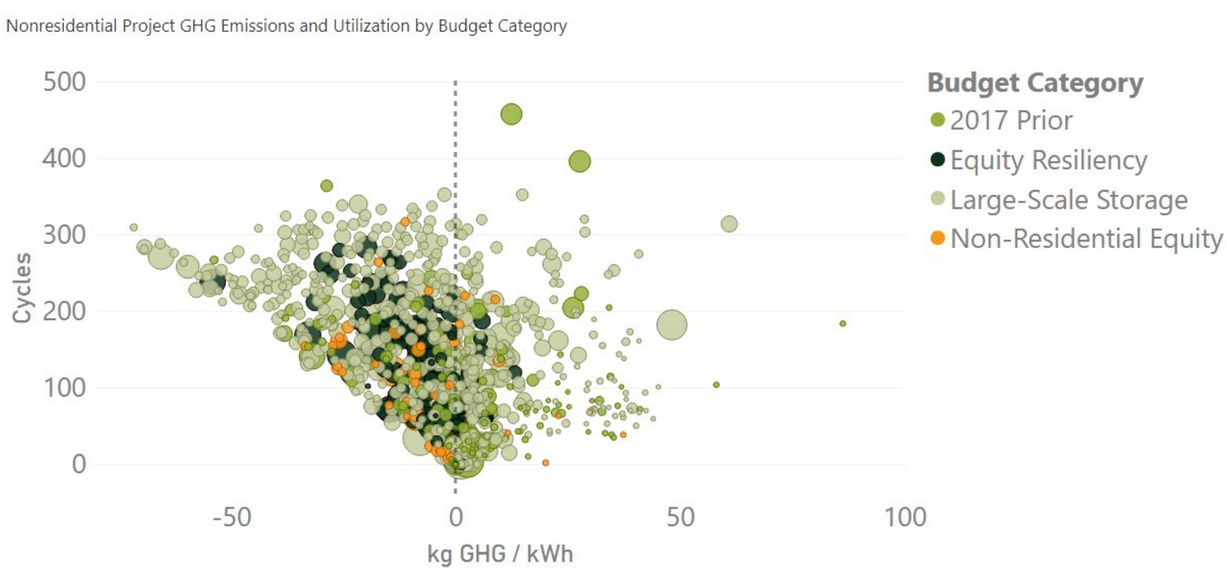
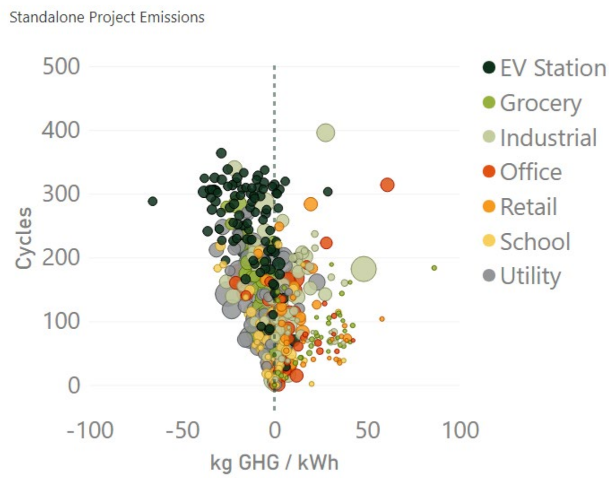
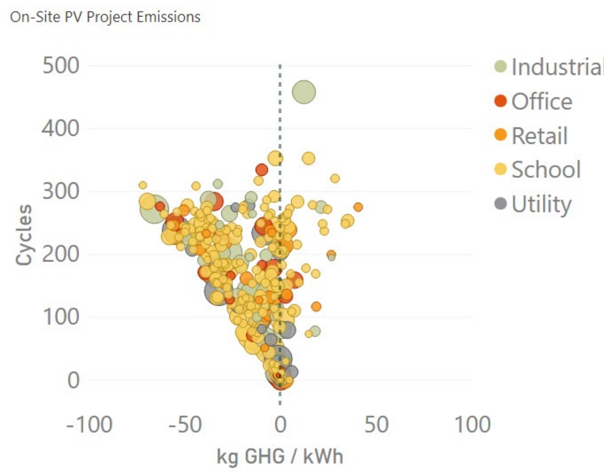


FIGURE 4-127: NONRESIDENTIAL PROJECT GHG EMISSIONS AND UTILIZATION BY ON-SITE GENERATION





Residential

Figure 4-128 presents the range in GHG emission reductions (-) or increases (+) for the sample of residential projects analyzed as part of the 2023 impact evaluation by upfront payment date. We observe significant GHG emissions reductions across the residential sector, independent of the length of time the system has been installed and operable – with average emissions reductions ranging from 15 kg/kWh to 22 kg/kWh. Distributions of emissions reveal some variability. Despite some project variance, the upper quartile for each payment year grouping is negative which signals that 75% or more projects were reducing emissions in 2023 (Figure 4-129).

FIGURE 4-128: EMISSIONS (KILOGRAMS GHG/KWH) FOR RESIDENTIAL SYSTEMS BY UPFRONT PAYMENT YEAR

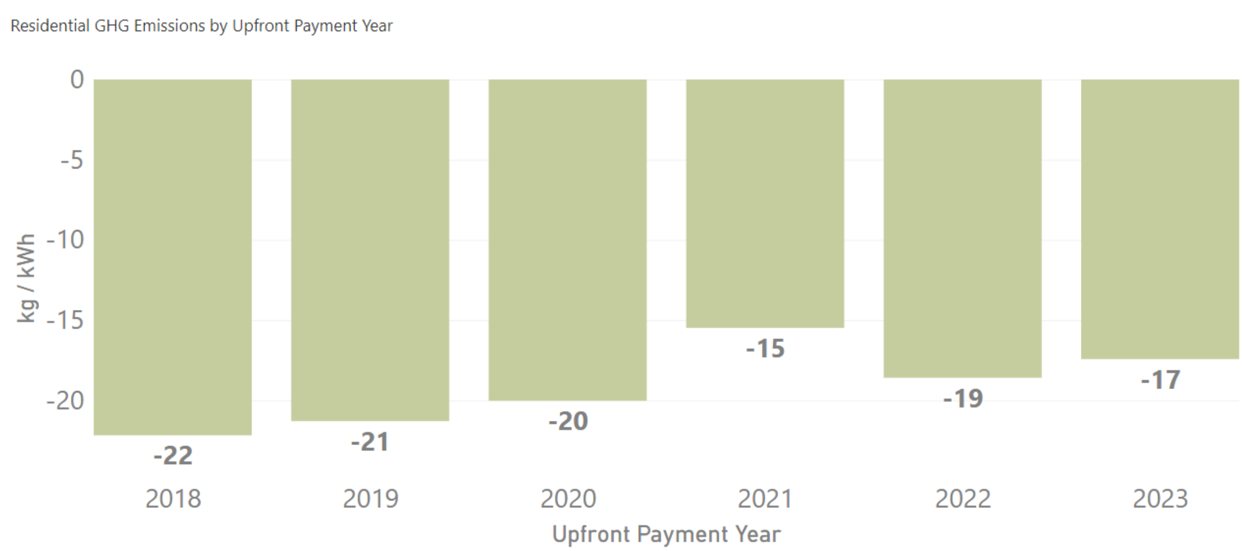


FIGURE 4-129: DISTRIBUTION OF EMISSIONS FOR RESIDENTIAL SYSTEMS BY UPFRONT PAYMENT YEAR

From a GHG perspective, the value of charging during on-site PV generating hours cannot be overstated. Furthermore, discharging in late afternoon and early evening, when on-site generation and grid-level renewable generation wanes, provides systems with an opportunity to reduce emissions during high marginal emission periods. These high marginal emissions periods also generally fall within newer on-peak TOU periods, so customers also have an opportunity to realize bill savings if discharging is coincident with high marginal emissions periods.

In winter months, marginal emissions are lowest during daylight hours when grid-scale renewables are generating and demand for A/C loads is far less than in summer months. In the summer, marginal emissions are highest during the early morning and, most significantly, during early evening hours on most days. Paired residential systems are charging in the morning and early afternoon from on-site PV which aligns well with lower marginal emissions.

Well-utilized PV paired residential systems are generally conducting 1) TOU arbitrage without export, 2) TOU arbitrage with export – either regularly or exclusively during specific times like an ELRP event, 3) self-consumption, or 4) some combination of all. We also observe under-utilization – not at a fleet or sector level – but from project to project. Idle, under-utilized systems are likely servicing a load much less than the capacity of the system or are in exclusive back-up mode, which is not allowed within the SGIP. We also observe some systems paired with PV that were charging from solar in 2021 or 2022, but begin charging the battery overnight in 2023, perhaps to take advantage of extremely low off-peak EV billed rates. This latter behavior is far more infrequent and is like that of standalone systems, but the change in charge timing has a dramatic effect on system emissions.

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The prevalent residential operating modes are presented below in Figure 4-130 through Figure 4-132. Self-consumption is the most frequently observed dispatch behavior in the sample of residential PV paired systems (64%), followed by TOU arbitrage (30%). The mode referred to as "Under-Utilization" combines systems that are under-utilized or remained idle throughout the entirety of the metering period (roughly 6% of the sample). These figures show how PV-paired systems charging from on-site PV conducting TOU arbitrage are discharging the system on-peak only, where discharge from PV-paired systems conducting self-consumption extends outside the on-peak period and throughout the night. Systems paired with PV, but charging from grid energy (roughly 3% of PV paired projects) have a similar discharge pattern to standalone systems (1% of all projects). Charging begins after 9pm with the greatest magnitude of charging occurring just after midnight.

FIGURE 4-130: RESIDENTIAL STORAGE DISPATCH AND MARGINAL EMISSIONS BY PV PAIRED SYSTEMS CHARGING FROM ON-SITE PV

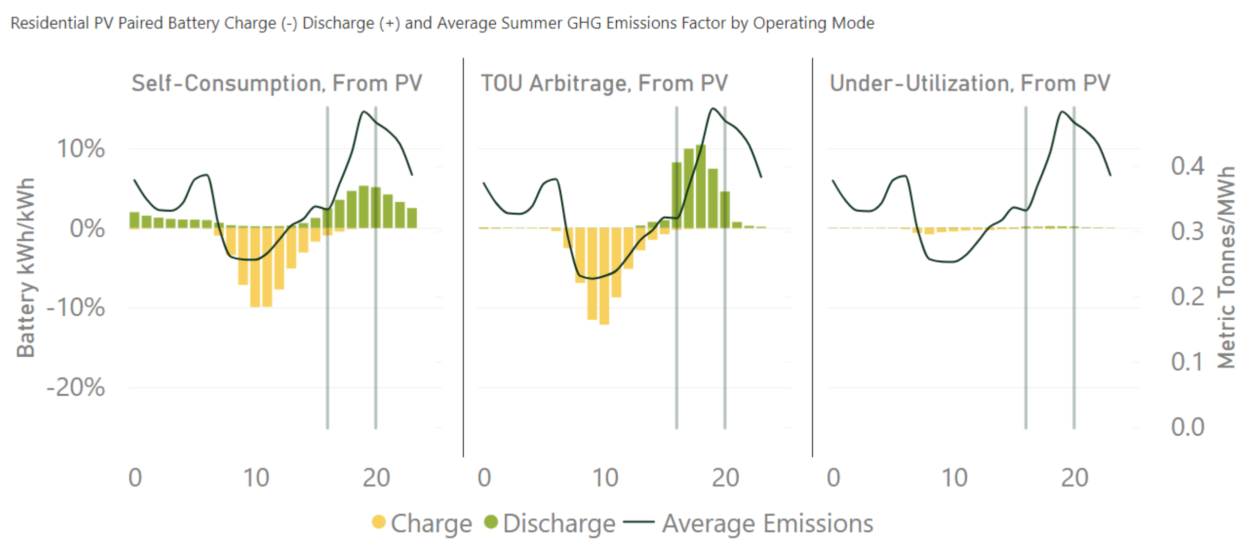


FIGURE 4-131: RESIDENTIAL STORAGE DISPATCH AND MARGINAL EMISSIONS BY PV PAIRED SYSTEMS CHARGING FROM GRID

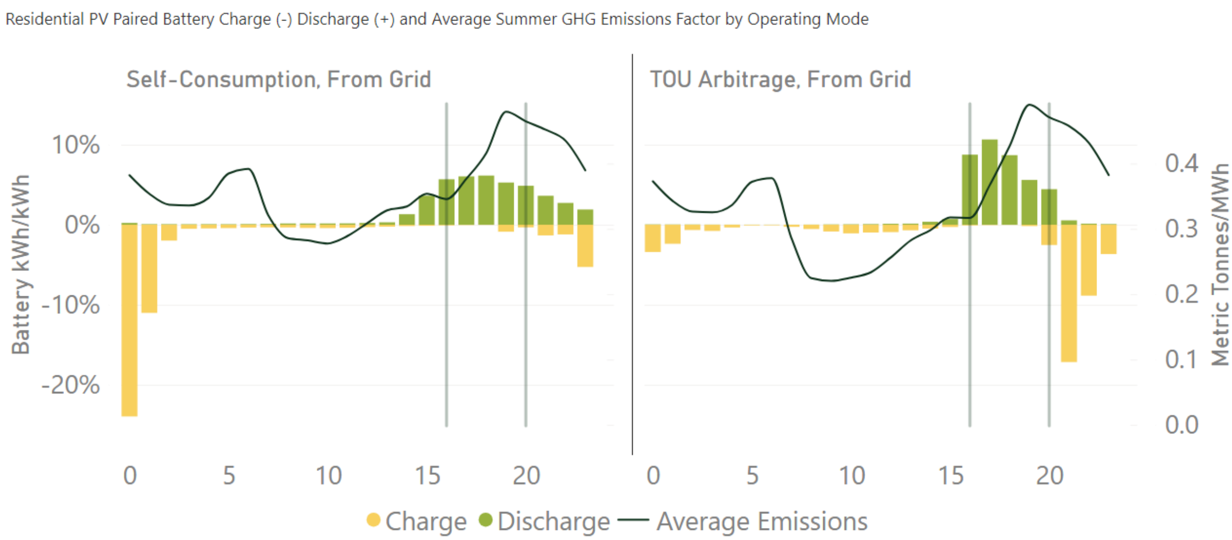
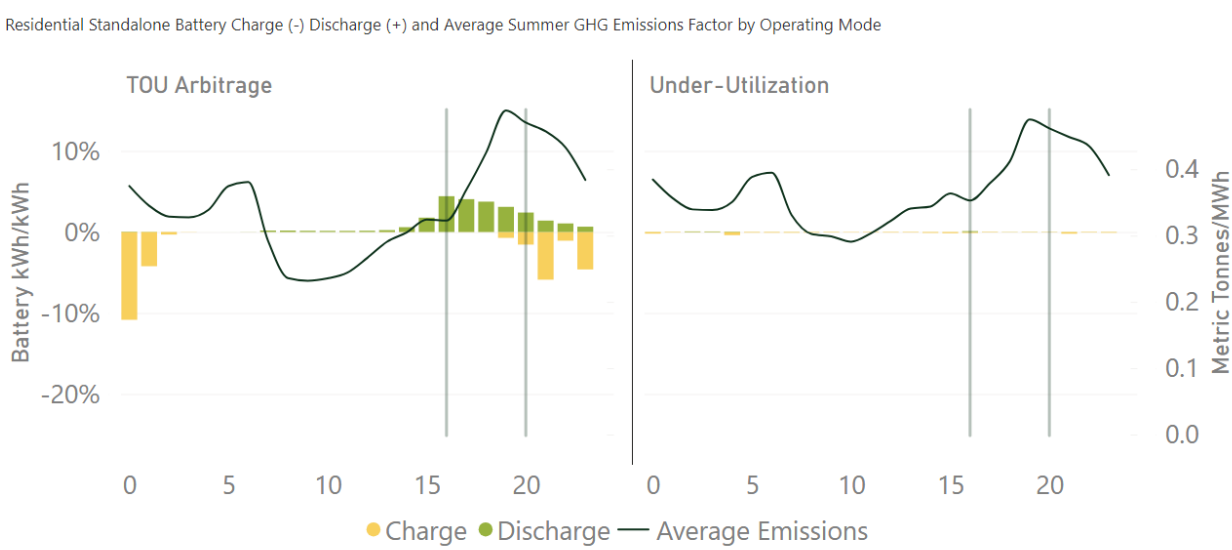


FIGURE 4-132: RESIDENTIAL STORAGE DISPATCH AND MARGINAL EMISSIONS FOR STANDALONE SYSTEMS



As noted previously, TOU on-peak periods generally run from 4pm to 9pm. Marginal emissions are highest during only a portion of that on-peak period on most days, so optimizing for the greatest emissions reductions can be achieved while maintaining bill savings benefits. Most residential systems are two- or three-hour batteries, so a system might discharge beginning at 4pm to reduce billed energy imports. If discharged at full capacity, the battery would be exhausted before 7pm and likely sooner if the SOC threshold is 20 or 30%. If marginal emissions peak during 7 pm or 8 pm, the system has lost the opportunity to maximize emissions reductions. If discharge was held to 7 pm or 8 pm the customer could realize virtually identical bill savings, with the added benefit of discharging during a period of greater grid stress and emissions.

Some of this nuanced behavior is captured below in Figure 4-133. Overall, charge timing is consistent across manufacturers with summer magnitudes greater than winter as systems are utilized more. Equip A, C, and D exhibit most discharge throughout on-peak hours, with some discharge extending thereafter. This suggests a blend of arbitrage and self-consumption across the respective fleets. Equip B exhibits different behavior with discharge occurring in the 6pm to 8pm hours of the on-peak period almost exclusively in 2023.[48] In previous evaluation years, this fleet was discharging identical to this, but during the 4pm to 6pm hours. We observe a fleet-level switch in timing of discharge for this cohort in the summer of 2021, and this behavior extended through 2023. The new dispatch signal aligns better with marginal emissions during summer months than the previous one.

FIGURE 4-133: RESIDENTIAL SUMMER STORAGE DISPATCH AND MARGINAL EMISSIONS BY EQUIPMENT

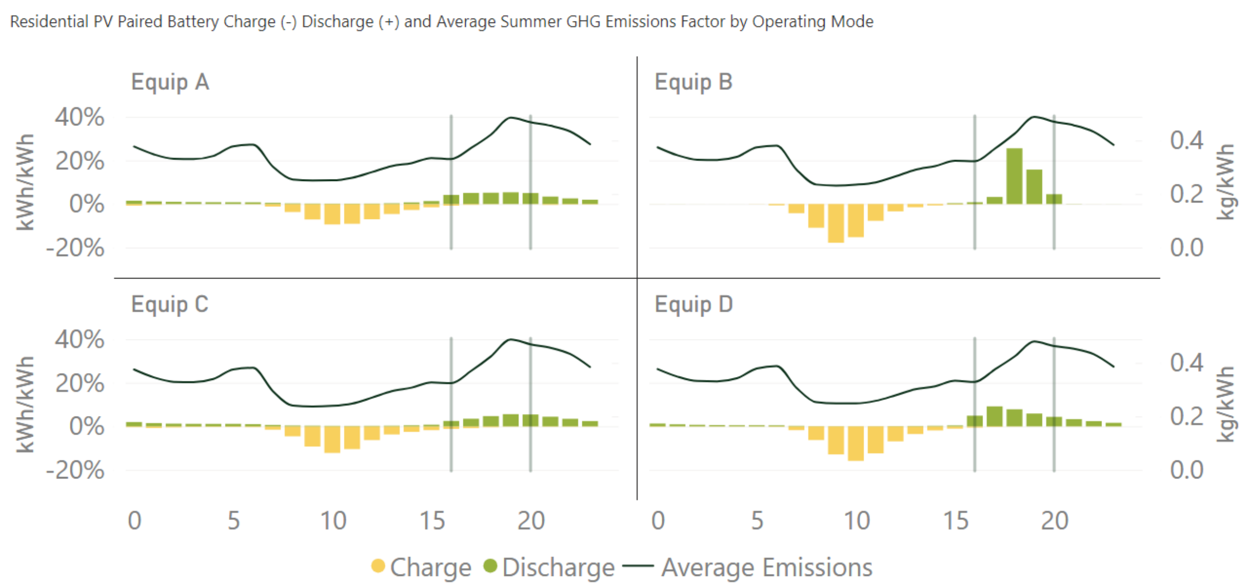
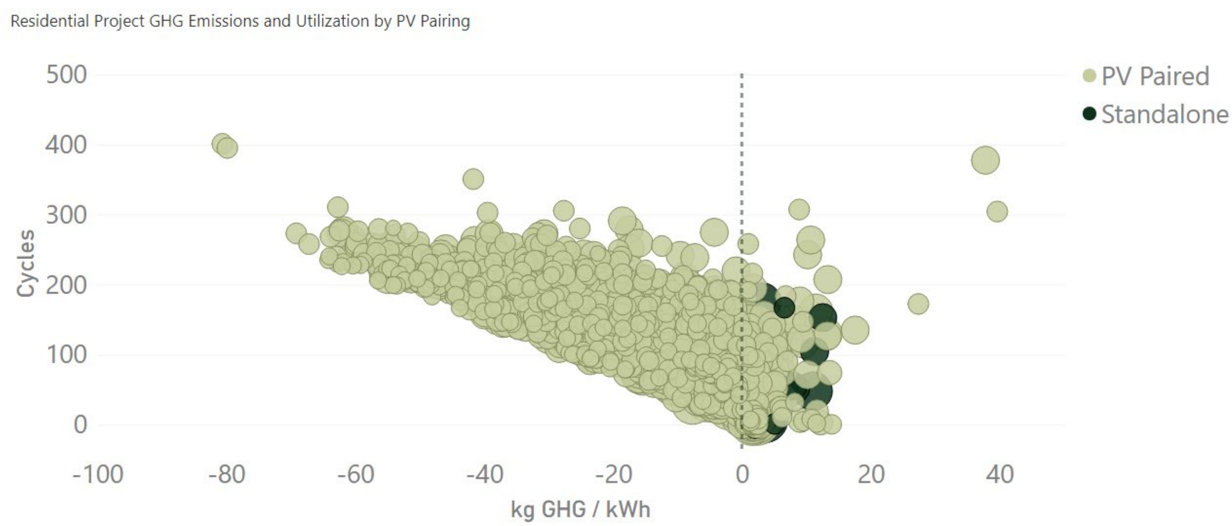


Figure 4-134 presents the project specific annual GHG emissions impacts for each residential project in 2023 by PV pairing. Emissions in kg GHG/kWh of capacity are represented on the horizontal axis with emissions reductions moving negative to left and increases moving right along the axis. Annual cycles, a proxy for system utilization, are also plotted on the vertical axis to highlight the correlation between

[48] Over 50% of kWh capacity, on average, is discharging during this time.

greater utilization and emissions magnitudes. PV paired systems are almost invariably reducing emissions (if well utilized) and standalone systems are all increasing emissions. The emissions differentials between charging overnight and discharging on-peak are not sufficient for standalone systems to realize emissions reductions like observed with PV paired systems charging from on-site PV during much lower emissions hours.

FIGURE 4-134: RESIDENTIAL PROJECT GHG EMISSIONS AND UTILIZATION BY PV PAIRING



Project emissions for PV paired systems conducting arbitrage, self-consumption or doing nothing (a proxy for under-utilization or backup) are presented below in Figure 4-135. There are no discernable differences in emissions from systems performing TOU arbitrage versus self-consumption, although systems conducting the latter are generally utilized more often. Idle systems all lead to small increases in emissions as system parasitic loads accumulate over the course of the year.

FIGURE 4-135: RESIDENTIAL PROJECT GHG EMISSIONS AND UTILIZATION BY OPERATING MODE

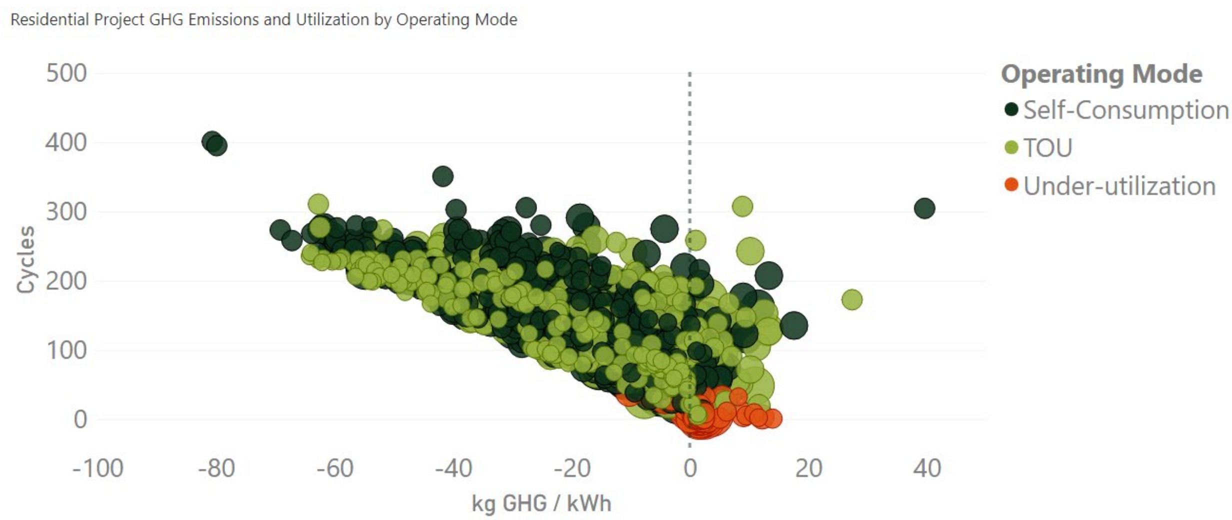
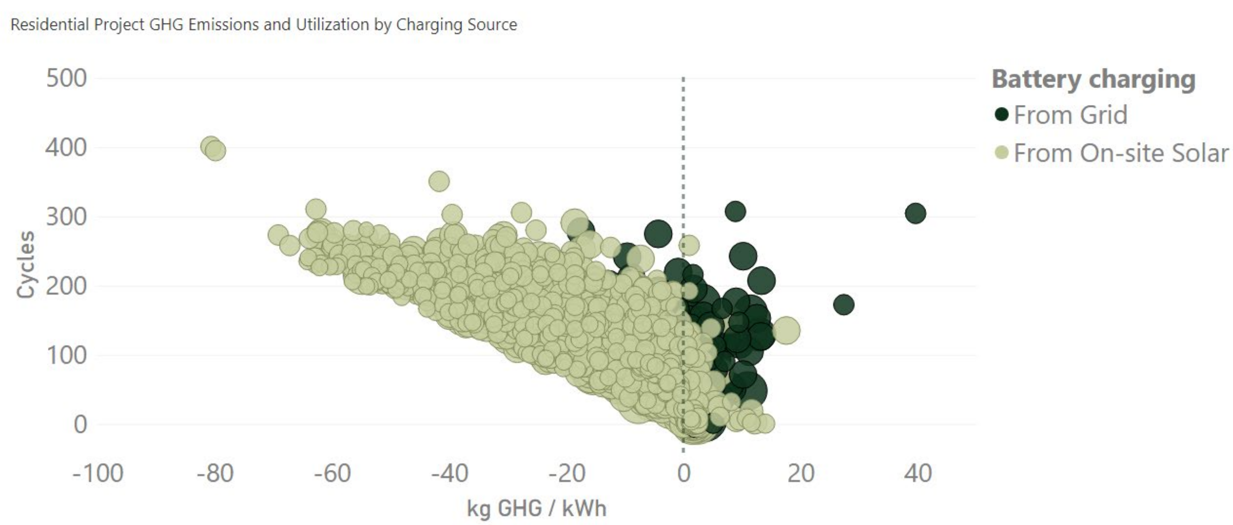


Figure 4-136 presents emissions based on the source of energy storage charging. Systems paired with PV, but charging from grid energy after the on-peak or overnight are increasing emissions, much like standalone systems are doing. Again, the emissions differentials between charging overnight and discharging on-peak are not sufficient for these systems to realize emissions reductions like observed if these systems charged from on-site PV instead.

FIGURE 4-136: RESIDENTIAL PROJECT GHG EMISSIONS AND UTILIZATION BY CHARGING SOURCE



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Overall GHG Impact Summaries

Below we summarize the GHG impacts discussed above for both the nonresidential and residential sectors, respectively. Summaries are provided by different domains of interest, including by PA, PV pairing, legacy status, and upfront payment year.

FIGURE 4-137: SUMMARY OF NONRESIDENTIAL GHG IMPACTS BY PA

n Prjs, kWh, kW, GHG kg/kWh, Baseline GHG, Post GHG, % Reduction
BY PROGRAM ADMINISTRATOR

Program Administrator	n Prjs	kW	kWh	Baseline GHG	Post GHG	% Reduction	GHG kg/kWh
CSE	187	194	486	929	925	-0.4%	-7
PG&E	297	275	739	1,218	1,212	-0.4%	-6
SCE	450	283	692	810	799	-1.3%	-8
SCG	54	402	1,142				-4
Overall	**988**	**270**	**691**	**937**	**931**	**-0.7%**	**-7**

FIGURE 4-138: SUMMARY OF NONRESIDENTIAL GHG IMPACTS BY ON-SITE GENERATION

n Prjs, kWh, kW, GHG kg/kWh, Baseline GHG, Post GHG, % Reduction
BY ON-SITE GENERATION

On-Site Generation	n Prjs	kW	kWh	Baseline GHG	Post GHG	% Reduction	GHG kg/kWh
On-site PV	377	255	611	722	711	-1.6%	-14
Standalone	611	280	741	1,038	1,033	-0.4%	-3
Overall	**988**	**270**	**691**	**937**	**931**	**-0.7%**	**-7**

FIGURE 4-139: SUMMARY OF NONRESIDENTIAL GHG IMPACTS BY BUDGET CATEGORY

n Prjs, kWh, kW, GHG kg/kWh, Baseline GHG, Post GHG, % Reduction
BY BUDGET CATEGORY

Budget Category	n Prjs	kW	kWh	Baseline GHG	Post GHG	% Reduction	GHG kg/kWh
2017 Prior	173	249	497	2,439	2,440	0.0%	0
Equity Resiliency	157	257	1,272	165	156	-5.6%	-9
Large-Scale Storage	608	284	608	1,052	1,045	-0.6%	-7
Storage Equity	50	225	558	671	659	-1.7%	-8
Overall	**988**	**270**	**691**	**937**	**931**	**-0.7%**	**-7**

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FIGURE 4-140: SUMMARY OF NONRESIDENTIAL GHG IMPACTS BY UPFRONT PAYMENT YEAR

n Prjs, kWh, kW, GHG kg/kWh, Baseline GHG, Post GHG, % Reduction
BY PAYMENT YEAR

Payment Year	n Prjs	kW	kWh	Baseline GHG	Post GHG	% Reduction	GHG kg/kWh
2015	11	360	721	9,679	9,681	0.0%	2
2016	22	141	281	2,646	2,647	0.1%	2
2017	41	234	468	1,160	1,169	0.8%	2
2018	50	166	329	1,442	1,434	-0.5%	-9
2019	177	160	330	1,620	1,614	-0.4%	-8
2020	63	334	745	1,870	1,871	0.1%	1
2021	117	272	586	1,222	1,215	-0.5%	-7
2022	163	244	800	346	332	-3.9%	-14
2023	118	336	1,140	329	320	-2.7%	-9
Overall	**762**	**243**	**641**	**1,011**	**1,003**	**-0.7%**	**-8**

FIGURE 4-141: SUMMARY OF NONRESIDENTIAL GHG IMPACTS BY BUILDING TYPE

n Prjs, kWh, kW, GHG kg/kWh, Baseline GHG, Post GHG, % Reduction
BY BUILDING TYPE

Building Type	n Prjs	kW	kWh	Baseline GHG	Post GHG	% Reduction	GHG kg/kWh
All Others	162	334	874	1,664	1,656	-0.5%	-6
EV Station	100	240	451	623	610	-2.1%	-13
Grocery	66	103	440	773	763	-1.3%	-9
Industrial	142	383	837	1,335	1,337	0.2%	-1
Office	71	379	823	988	982	-0.6%	0
Retail	73	217	457	1,404	1,401	-0.2%	-3
School	267	172	420	365	355	-2.7%	-13
Utility	107	364	1,349	356	347	-2.5%	-8
Overall	**988**	**270**	**691**	**937**	**931**	**-0.7%**	**-7**

FIGURE 4-142: SUMMARY OF NONRESIDENTIAL GHG IMPACTS BY PROGRAM YEAR

n Prjs, kWh, kW, GHG kg/kWh, Baseline GHG, Post GHG, % Reduction
BY PROGRAM YEAR

Program Year	n Prjs	kW	kWh	Baseline GHG	Post GHG	% Reduction	GHG kg/kWh
2012	4	294	588	849	845	-0.4%	-4
2013	4	15	30	437	436	-0.2%	0
2014	55	260	520	5,364	5,372	0.1%	2
2015	67	296	593	1,278	1,275	-0.2%	-1
2016	43	177	354	1,058	1,059	0.1%	-1
2017	320	202	418	1,383	1,379	-0.3%	-6
2018	59	447	972	1,347	1,351	0.3%	2
2019	79	373	775	897	888	-1.0%	-4
2020	304	286	911	404	394	-2.6%	-11
2021	49	322	1,349	298	285	-4.1%	-11
2022	4	218	432	241	235	-2.7%	-7
Overall	**988**	**270**	**691**	**937**	**931**	**-0.7%**	**-7**

FIGURE 4-143: SUMMARY OF RESIDENTIAL GHG IMPACTS BY PA

n Prj, kW, kWh, Baseline GHG, Post GHG, % Reduction, GHG kg/kWh
BY PROGRAM ADMINISTRATOR

Program Administrator	n Prj	kW	kWh	Baseline GHG	Post GHG	% Reduction	GHG kg/kWh
CSE	296	8	21	46	19	-58%	-26
PG&E	1054	8	22	93	82	-12%	-11
SCE	593	8	19	148	123	-17%	-26
SCG	134	8	21	92	74	-20%	-17
Overall	**2077**	**8**	**21**	**100**	**83**	**-17%**	**-17**

FIGURE 4-144: SUMMARY OF RESIDENTIAL GHG IMPACTS BY ON-SITE GENERATION

n Prj, kW, kWh, Baseline GHG, Post GHG, % Reduction, GHG kg/kWh
BY ON-SITE PV

On-Site PV	n Prj	kW	kWh	Baseline GHG	Post GHG	% Reduction	GHG kg/kWh
PV Paired	2055	8	21	100	82	-18%	-18
Standalone	22	12	31	114	118	3%	5
Overall	**2077**	**8**	**21**	**100**	**83**	**-17%**	**-17**

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FIGURE 4-145: SUMMARY OF RESIDENTIAL GHG IMPACTS BY PAYMENT YEAR

n Prj, kW, kWh, Baseline GHG, Post GHG, % Reduction, GHG kg/kWh
BY PAYMENT YEAR

Payment Year	n Prj	kW	kWh	Baseline GHG	Post GHG	% Reduction	GHG kg/kWh
2018	98	6	14	166	146	-12%	-22
2019	187	7	16	143	123	-14%	-21
2020	274	7	18	125	105	-16%	-20
2021	734	9	24	95	79	-17%	-16
2022	529	8	21	86	68	-21%	-18
2023	255	8	19	80	64	-20%	-17
Overall	**2077**	**8**	**21**	**100**	**83**	**-17%**	**-17**

FIGURE 4-146: SUMMARY OF RESIDENTIAL GHG IMPACTS BY PA BY BUDGET CATEGORY

n Prj, kW, kWh, Baseline GHG, Post GHG, % Reduction, GHG kg/kWh
BY BUDGET CATEGORY

Budget Category	n Prj	kW	kWh	Baseline GHG	Post GHG	% Reduction	GHG kg/kWh
All Others	2	10	26	175	146	-17%	-29
Equity Resiliency	567	11	28	84	68	-19%	-16
Large-Scale Storage	104	17	43	96	84	-13%	-13
Small Residential Storage	1404	7	16	111	92	-17%	-20
Overall	**2077**	**8**	**21**	**100**	**83**	**-17%**	**-17**

FIGURE 4-147: SUMMARY OF RESIDENTIAL GHG IMPACTS BY PA BY PROGRAM YEAR

n Prj, kW, kWh, Baseline GHG, Post GHG, % Reduction, GHG kg/kWh
BY PROGRAM YEAR

Program Year	n Prj	kW	kWh	Baseline GHG	Post GHG	% Reduction	GHG kg/kWh
2017	96	7	17	163	142	-13%	-21
2018	204	7	16	156	136	-13%	-21
2019	225	8	21	118	102	-14%	-17
2020	886	9	24	92	76	-18%	-16
2021	428	8	21	87	69	-21%	-18
2022	185	7	17	88	71	-20%	-19
2023	53	7	15	45	35	-21%	-13
Overall	**2077**	**8**	**21**	**100**	**83**	**-17%**	**-17**

FIGURE 4-148: SUMMARY OF RESIDENTIAL GHG IMPACTS BY OPERATING MODE

n Prj, kW, kWh, Baseline GHG, Post GHG, % Reduction, GHG kg/kWh
BY OPERATING MODE

Operating Mode	n Prj	kW	kWh	Baseline GHG	Post GHG	% Reduction	GHG kg/kWh
Other/Unknown	16	8	21	90	91	1%	-1
Self-Consumption	1323	9	22	81	62	-24%	-19
TOU Arbitrage	617	7	17	147	129	-12%	-18
Under-Utilization/Back-up	121	10	25	126	127	1%	1
Overall	**2077**	**8**	**21**	**100**	**83**	**-17%**	**-17**

FIGURE 4-149: SUMMARY OF RESIDENTIAL GHG IMPACTS BY CHARGING SOURCE

n Prj, kW, kWh, Baseline GHG, Post GHG, % Reduction, GHG kg/kWh
BY ON-SITE PV, CHARGING

On-Site PV	Charging	n Prj	kW	kWh	Baseline GHG	Post GHG	% Reduction	GHG kg/kWh
PV Paired	From Grid	58	10	25	132	130	-1%	2
PV Paired	Solar	1997	8	21	99	80	-19%	-19
Standalone	From Grid	22	12	31	114	118	3%	5
Overall		**2077**	**8**	**21**	**100**	**83**	**-17%**	**-17**

FIGURE 4-150: SUMMARY OF RESIDENTIAL GHG IMPACTS BY EQUIPMENT

n Prj, kW, kWh, Baseline GHG, Post GHG, % Reduction, GHG kg/kWh
BY EQUIPMENT

Equipment	n Prj	kW	kWh	Baseline GHG	Post GHG	% Reduction	GHG kg/kWh
Equip A	1614	9	23	96	78	-19%	-17
Equip B	178	5	9	219	198	-9%	-27
Equip C	62	7	19	63	50	-20%	-15
Equip D	223	6	13	99	90	-10%	-13
Overall	**2077**	**8**	**21**	**100**	**83**	**-17%**	**-17**

4.4.2 Generation

Passage of SB 412 in 2009 required the CPUC to establish GHG goals for the SGIP. Therefore, most of the generation projects in the population today are designed with GHG goals in mind. Non-renewable projects, in general, were found to increase emissions during 2023. Two non-renewable projects, both Gas Turbines with high levels of heat recovery, were found to decrease emissions. Renewably fueled projects reduced emissions, with systems with vented baselines contributing to the highest reductions in emissions. Non-fueled technologies like wind and pressure reduction turbines also reduced emissions.

The projects whose impacts are observed in this section include all projects with metered data for all applicable streams of data. For example, wind turbine projects only require energy generation data. Combustion technologies without heat recovery would only require energy generation and fuel consumption data. However, combustion technologies with heat recovery would require energy generation, fuel consumption, and heat recovery data. Heat recovery is notoriously difficult to meter. The limited quantity of metered heat recovery data is used in the calculation of population-level GHG estimates for CHP systems using methods discussed in Appendix E.

The GHG impact analysis is limited to carbon dioxide (CO_2) and CO_2 equivalent (CO_2eq) emissions impacts associated with SGIP projects. The discussion is organized into the following subsections:

- Methodology Overview and Summary of Environmental Impacts
- Non-renewable Generation Project Impacts
- Renewable Biogas Generation Project Impacts
- Waste Gas and Non-Fueled Project Impacts

The scope of this analysis is further limited to the operational impacts of SGIP projects and does not discuss any lifecycle emissions impacts that occur during the manufacturing, transportation, and construction of SGIP projects. A more detailed discussion of the environmental impacts methodology is included in Appendix D.

Background and Baseline Discussion

Emission impacts are calculated as the difference between the emissions generated by SGIP projects and baseline emissions that would have occurred in the absence of the program. The sources of these emissions (generated and avoided) vary by technology and fuel type. For example, all distributed generation technologies avoid emissions associated with displacing central station grid electricity, but only those that recover useful heat may avoid emissions associated with displacing boiler use.

Grid Electricity Baseline

The passage of SB 412 established a maximum GHG emissions rate for SGIP generation technologies. Beginning in 2011, eligibility for SGIP generation projects was limited to projects that did not exceed an emissions rate of 379 kg CO_2/MWh over ten years. Later, the CPUC revised the maximum GHG emissions rate for eligibility to 350 kg CO_2/MWh over ten years for projects applying to the SGIP in 2016.

When developing these emission factors for eligibility, the CPUC and the SGIP PAs must look forward and forecast what baseline grid conditions will look like during an SGIP project's life. These forecasts must make assumptions about power plant efficiencies and the useful life of SGIP projects. By contrast, an impact evaluation has the benefit of being backward-looking and can leverage historical data to quantify the grid electricity baseline. Consequently, the avoided grid emissions rates used in this impact evaluation report to assess project performance are different than the avoided grid emissions factors used to screen SGIP applications for program eligibility requirements. This evaluation relies on avoided grid emissions rates developed by WattTime as part of the SGIP GHG Signal efforts.[49]

Non-Renewable Generation Project Greenhouse Gas Impacts

SGIP non-renewable generation projects include fuel cells (CHP and electric-only), gas turbines, internal combustion engines, and microturbines. These include those directed biogas projects which have met their contractual procurement requirements and are assumed to no longer procure renewable fuel. These projects are powered by natural gas and are used to generate electricity to serve a customer's load. These projects produce emissions that are proportional to the amount of fuel they consume. In the absence of the program, the customer's electrical load would have been served by the electricity distribution company. If SGIP projects only served electrical loads, they would need to generate electricity more cleanly than the avoided marginal grid generator to achieve GHG emission reductions.

CHP projects recover waste heat and use it to serve on-site thermal loads, like a customer's heating or cooling needs. In the absence of the SGIP, a heating end-use is assumed to be met by a natural gas boiler, and the cooling end-use met with an electric chiller. Natural gas boilers generate emissions associated with the combustion of gas to heat water. The emissions associated with electric chillers are due to the central station plant that would have generated the electricity to run the chiller. Emissions impacts are the difference between the SGIP emissions and those avoided emissions. Metered non-renewable gas turbines were found to reduce emissions due to the high rate of heat recovery in gas turbines.

49 The real-time marginal GHG emissions signal developed by WattTime represents the compliance signal for this evaluation and the SGIP, in general. These data are publicly available here: https://sgipsignal.com/.

FIGURE 4-151: OBSERVED NON-RENEWABLE PROJECT GREENHOUSE GAS IMPACTS RATES BY TECHNOLOGY TYPE

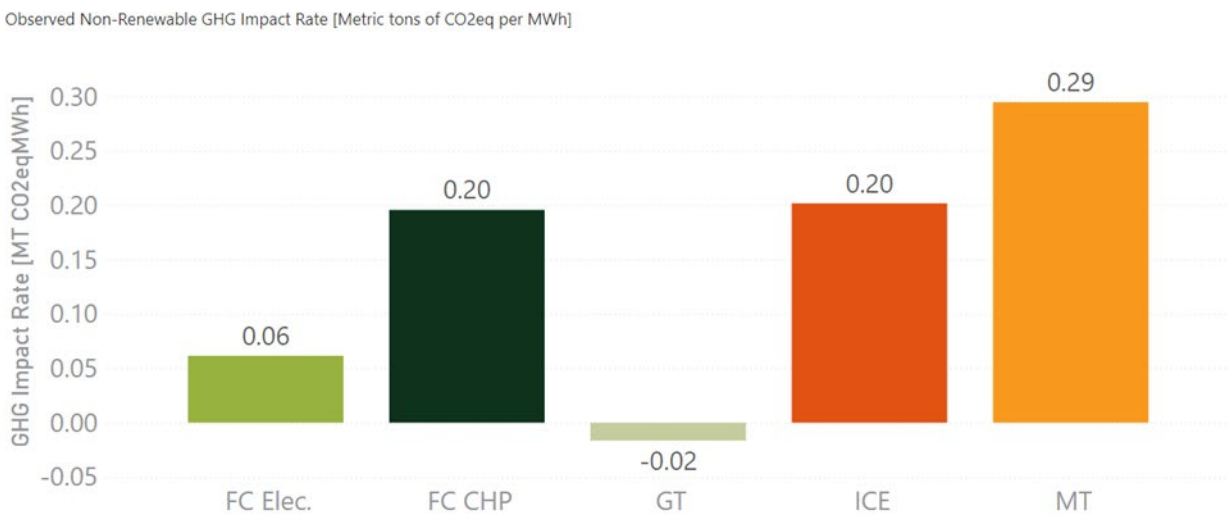


Table 4-5 shows the impact rates of the individual contributors to the GHG impact calculations. Non-renewable technologies have a higher emissions rate than the electrical power plants that they avoid (A > B). Even when accounting for the heating and cooling services avoided, the emissions impact (F) is generally higher, relative to the conventional energy services baseline.

TABLE 4-5: OBSERVED NON-RENEWABLE PROJECT GREENHOUSE GAS IMPACT RATES BY TECHNOLOGY TYPE [METRIC TONS OF CO_{2EQ} PER MWH]

Equipment Type	SGIP Emissions [A]	Electric Power Plant Emissions [B]	Heating Services [C]	Cooling Services [D]	Total Avoided Emissions [E = B+C+D]	Emissions Impact [F=A-E]
Fuel Cell Electric	0.40	0.34	0	0	0.34	0.06
Fuel Cell CHP	0.50	0.31	0.07	0.00	0.31	0.20
Gas Turbine	0.57	0.32	0.27	0.00	0.58	-0.02
Internal Combustion Engine	0.64	0.33	0.09	0.01	0.44	0.20
Microturbine	0.65	0.32	0.02	0.01	0.35	0.29
Total	**0.49**	**0.33**	**0.13**	**0.00**	**0.46**	**0.03**

Figure 4-152 shows the range of GHG impact rate for each project by equipment type, for 2023. Microturbines and internal combustion engines all increased emissions, while impact rates for fuel cells, varied, with most systems increasing emissions and a few decreasing emissions. Gas turbines and some all-electric fuel cells were found to decrease greenhouse gas emissions.

FIGURE 4-152: OBSERVED NON-RENEWABLE PROJECT-LEVEL GREENHOUSE GAS IMPACTS TECHNOLOGY TYPE

Renewable Biogas Project Impacts

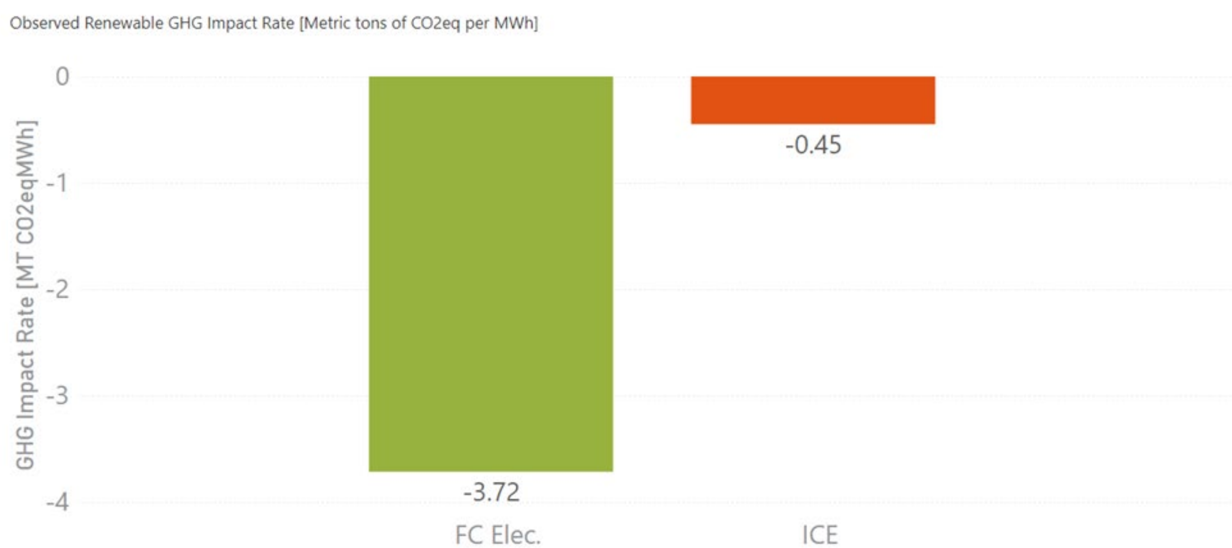
SGIP renewable biogas projects include CHP fuel cells, internal combustion engines, microturbines, and gas turbines. About 15% of the total SGIP rebated capacity is fueled, at least partially, by renewable biogas. Sources of biogas include landfills, water resource and recovery (WRRF), dairies, and food processing facilities. Analysis of the emission impacts associated with renewable biogas SGIP projects is more complex than for non-renewable projects. This complexity is due, in part, to the additional baseline component associated with biogas collection and treatment in the absence of the SGIP project installation. Also, some projects generate only electricity while others are CHP projects that use waste heat to meet site heating and cooling loads. Consequently, renewable biogas projects can directly impact emissions the same way that non-renewable projects can, but they also include emission impacts caused by the treatment of the biogas in the absence of the program.

Renewable biogas SGIP projects capture and use biogas that otherwise may have been emitted into the atmosphere (vented) or captured and burned (flared). By capturing and utilizing this gas, emissions from venting or flaring the gas are avoided. The concept of avoided biogas emissions is further explained in Appendix E.

When reporting emissions impacts from different types of greenhouse gases, total GHG emissions are reported in terms of metric tons of CO_2 equivalent (CO_2eq) so that direct comparisons can be made across technologies and energy sources. On a per mass unit basis, the global warming potential of CH_4 is 25 times that of CO_2. The biogas baseline estimates of vented emissions (CH_4 emissions from renewable SGIP facilities) are converted to CO_2eq by multiplying the metric tons of CH_4 by 25. In this section, CO_2eq emissions are reported if projects with a biogas venting baseline are included. Otherwise, CO_2 emissions are reported.

The 2023 GHG performance of renewably fueled biogas SGIP projects is summarized below in Figure 4-153 by technology type and biogas baseline. The only all-renewable fueled projects where metered data was available were all-electric fuel cells and internal combustion engines. All renewable fueled projects were found to decrease GHG impacts.

FIGURE 4-153: OBSERVED RENEWABLE PROJECT GREENHOUSE GAS IMPACT RATES BY TECHNOLOGY TYPE



All renewable biogas technologies reduced GHG emissions regardless of the biogas baseline type. Table 4-6 highlights the impact rates for renewably fueled technologies, separated by biogas baseline type. Technologies with flaring biogas achieved reductions between 0.36 and 0.45 metric tons of CO_2 per MWh. All-electric fuel cells with vented biogas baselines achieved GHG reductions that were an order of magnitude greater, over 3 metric tons of CO_2eq per MWh.

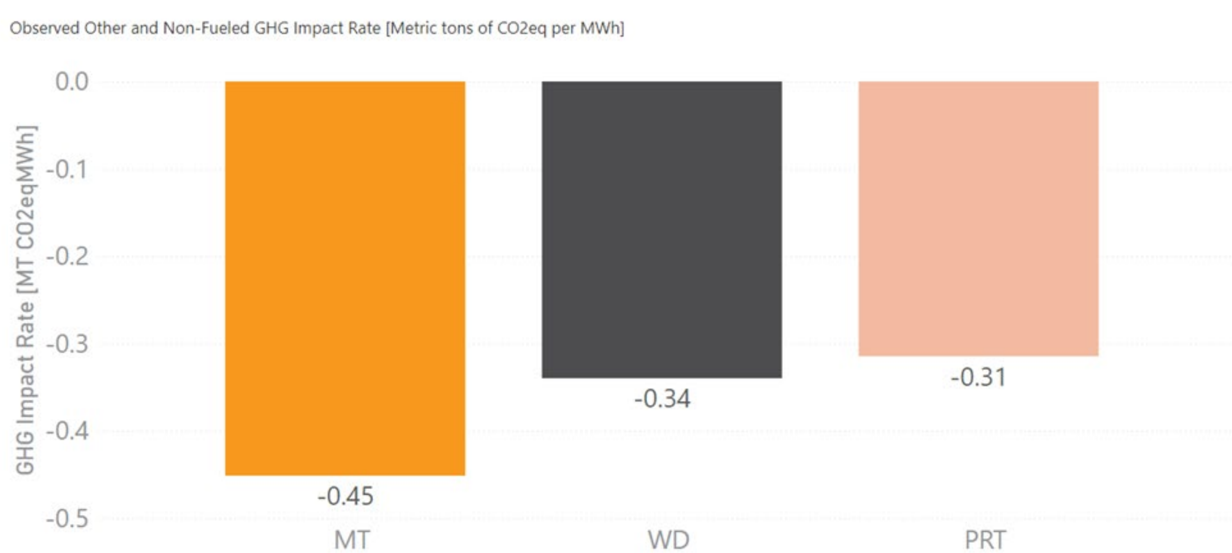
TABLE 4-6: OBSERVED RENEWABLE PROJECT GREENHOUSE GAS IMPACTS BY TECHNOLOGY TYPE [METRIC TONS OF CO_{2EQ} PER MWH]

Equipment Type & Baseline Type	SGIP Emissions [A]	Electric Power Plant Emissions [B]	Heating Services [C]	Biogas Treatment [D]	Total Avoided Emissions [E = B+C+D]	Emissions Impact [F=A-E]
Fuel Cell Electric *(Flare)*	0.54	0.36	0	0.54	0.90	-0.36
Fuel Cell Electric *(Vent)*	0.37	0.36	0	3.37	3.73	-3.36
Internal Combustion Engine *(Flare)*	0.55	0.36	0.09	0.55	1.00	-0.45
Total	**0.49**	**0.36**	**0.05**	**1.59**	**2.01**	**-1.52**

Other and Non-Fueled Projects Impacts

Wind and pressure reduction turbine projects do not consume any type of fuel and do not recover waste heat. Their emissions reduction rates are equal to the emissions rate of the grid, as described in Appendix D. Figure 4-154 summarizes the impact rate and overall GHG impact from these projects. A single microturbine was also fueled by waste gas from oil and gas drilling processes. All other and non-fueled projects were found to decrease emissions.

FIGURE 4-154: OBSERVED OTHER AND NON-FUELED GREENHOUSE GAS IMPACT RATES BY TECHNOLOGY TYPE



The individual impacts are shown below in Table 4-7. There are no baseline emissions for non-fueled technologies, so the emissions impact is the inverse of the electric power plant emissions for the same amount of electrical generation.

TABLE 4-7: OBSERVED NON-FUELED PROJECT GREENHOUSE GAS IMPACT RATES BY TECHNOLOGY TYPE

Equipment Type	SGIP Emissions [A]	Electric Power Plant Emissions [B]	Heating Services [C]	Biogas Treatment [D]	Total Avoided Emissions [E B + C + D]	Emissions Impact [F=A-E]
Microturbine	0.68	0.33	0.12	0.68	1.13	-0.45
Wind	0	0.34	0	0	0.34	-0.34
Pressure Reduction Turbine	0	0.31	0	0	0.31	-0.31
Total	**0**	**0.34**	**0.00**	**0.01**	**0.35**	**-0.34**

GHG Impact Summaries

Below we summarize the observed GHG impacts discussed above by technology type, and fuel type.

FIGURE 4-155: SUMMARY OF NON-RENEWABLE GHG IMPACTS BY TECHNOLOGY TYPE

Equipment Type	n Prj	Avg.Generation [GWh]	GHG (MT/MWh)
Microturbine	4	15.37	0.29
Internal Combustion Engine	3	10.09	0.20
Gas Turbine	2	449.09	-0.02
Fuel Cell CHP	1	2.89	0.20
Fuel Cell Electric	219	231.19	0.06
Total	**229**	**156.64**	**0.03**

FIGURE 4-156: SUMMARY OF RENEWABLE GHG IMPACTS BY TECHNOLOGY TYPE

Equipment Type	n Prj	Avg.Generation [GWh]	GHG (MT/MWh)
Internal Combustion Engine	3	10.63	-0.45
Fuel Cell Electric	2	3.38	-3.21
Total	**5**	**5.80**	**-1.52**

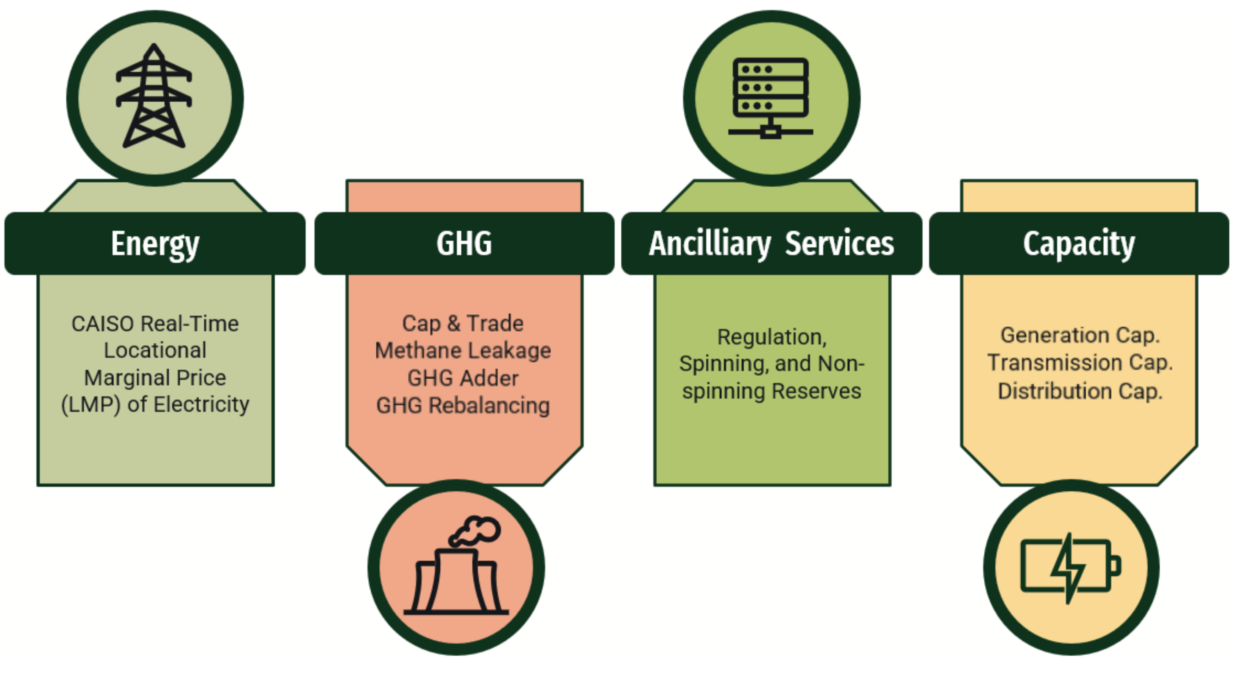
FIGURE 4-157: SUMMARY OF OTHER AND NON-FUELED GHG IMPACTS BY TECHNOLOGY TYPE

Equipment Type	n Prj	Avg.Generation [GWh]	GHG (MT/MWh)
Pressure Reduction Turbine	6	3.59	-0.31
Wind	17	61.52	-0.34
Microturbine	1	0.73	-0.45
Total	**24**	**21.95**	**-0.34**

4.5 UTILITY MARGINAL COST IMPACTS

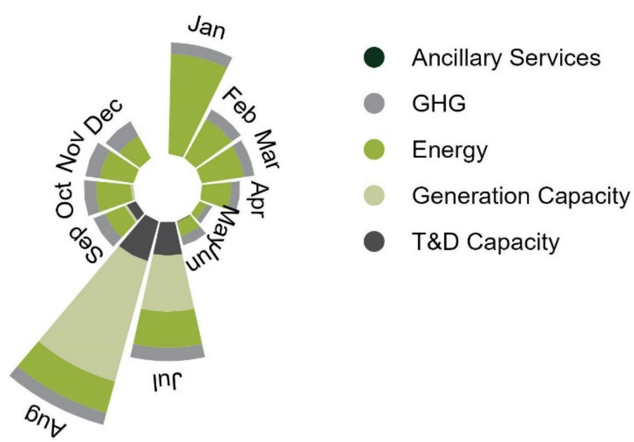
Utility marginal cost impacts for each IOU were calculated for each hour in 2023. Marginal cost rates ($/kWh) used in these calculations are consistent with assumptions in the 2023 Avoided Cost Calculator (ACC2023) and with data underlying the GHG impacts analysis. The marginal GHG emissions rates introduced in the previous section were calculated by WattTime using marginal electricity, natural gas and carbon price data, as well as assumptions from the ACC. The same marginal electricity and carbon price data were used to calculate utility marginal cost impacts as were used to calculate GHG impacts. The data and assumptions used for each utility cost component are described in detail in Appendix F. The electric utility costs that were included in this analysis are shown below in Figure 4-158.

FIGURE 4-158: ELECTRIC AVOIDED UTILITY COSTS



Energy costs, GHG adder, and cap and trade costs represent the most consistent share of avoided costs throughout the year. A high-level summary of these patterns is shown in Figure 4-159, where the values represent averages across the three electric IOUs.[50] During April and May, when there are longer days and plentiful grid-scale renewable generation without the A/C demand of summer months, these costs generally are lower. However, during summer months – June through September – there are some significantly capacity-constrained hours.

FIGURE 4-159: AVERAGE 2023 MARGINAL ELECTRIC UTILITY COSTS BY MONTH AND COST CATEGORY



Sources: CAISO and 2022 Avoided Cost Calculator

4.5.1 Energy Storage

Previous sections have detailed the nuanced observed behavior of nonresidential and residential energy storage systems within the SGIP. When the timing and magnitude of charge and discharge follow the price signal of a customer tariff or a marginal emissions signal, storage performance can lead to customer bill savings and avoided GHG emissions. The same is true for utility costs.

For energy storage systems to reduce utility costs, the marginal costs *avoided* during storage discharge must be greater than the marginal cost increase during storage charging. Since storage technologies inherently consume more energy during charging relative to energy discharged, the marginal cost rate must be lower during charging hours relative to discharge hours if utility cost savings are to be realized. In other words, SGIP storage systems that charge during lower marginal cost periods and discharge during

50 In this exhibit, losses are included with 'Energy' and methane leakage is included with 'GHG'.

higher marginal cost periods will provide a net benefit to utility systems.

Nonresidential Utility Avoided Costs

The normalized utility marginal avoided costs in 2023 are shown in Figure 4-160 by electric IOU for standalone nonresidential energy storage systems and those paired or co-located with on-site PV. Marginal avoided costs are positive (+) and marginal incurred costs are negative (-). The timing, magnitude and duration of nonresidential storage charge and discharge behavior provided an avoided cost benefit to all electric utilities in 2023. SGIP storage systems were charging during lower marginal cost periods – particularly systems paired with on-site PV – and discharging during higher cost periods which also coincide with billed on-peak hours and times of greater marginal emissions. Marginal costs are highest when energy prices are high, and generation capacity and transmission and distribution (T&D) systems are constrained. On average, energy storage systems are discharging during the most constrained hours (and not charging). The average marginal *avoided* cost (+) for standalone systems and those co-located or paired with on-site PV are similar for PG&E ($12/kWh compared to $11/kWh, respectively). For SCE and SDG&E systems paired or co-located with solar, avoided cost benefits are greater than standalone systems. For each utility throughout the year, the much more variable generation and T&D capacity components represent the most avoided cost benefits, followed by avoided energy costs.

FIGURE 4-160: NONRESIDENTIAL AVOIDED COST $ PER CAPACITY KWH BY IOU

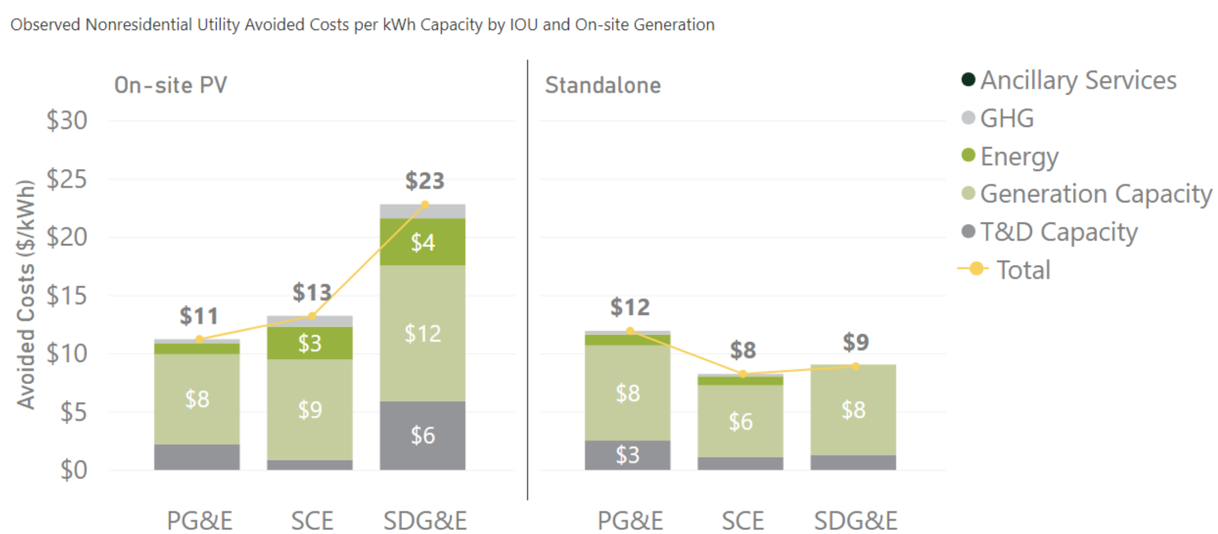


Figure 4-161 and Figure 4-162 provide the distribution of nonresidential project avoided costs for 2023. Moving right along the horizontal axis from zero signals avoided cost benefits to the utility. The vertical axis ties the utilization of the system in annual cycles to the utility costs, where a correlation between greater utilization and increased utility avoided cost benefit is evident. The size of the bubble corresponds to the relative kWh size of the system, with many of the smaller systems exhibiting lower utilization and small utility cost increases from performance in 2023. Finally, Figure 4-163 presents a box plot representing the distribution of project-specific avoided cost benefits across utility and presence of on-site generation or not.

FIGURE 4-161: NONRESIDENTIAL PROJECT AVOIDED COST $ PER CAPACITY KWH BY IOU

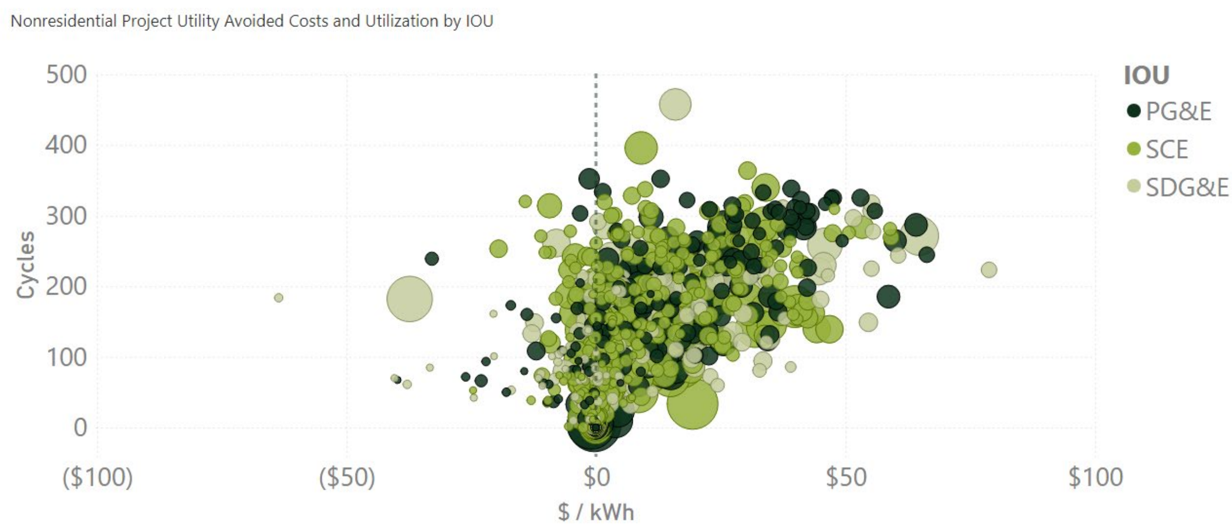


FIGURE 4-162: NONRESIDENTIAL PROJECT AVOIDED COST $ PER CAPACITY KWH BY ON-SITE GENERATION

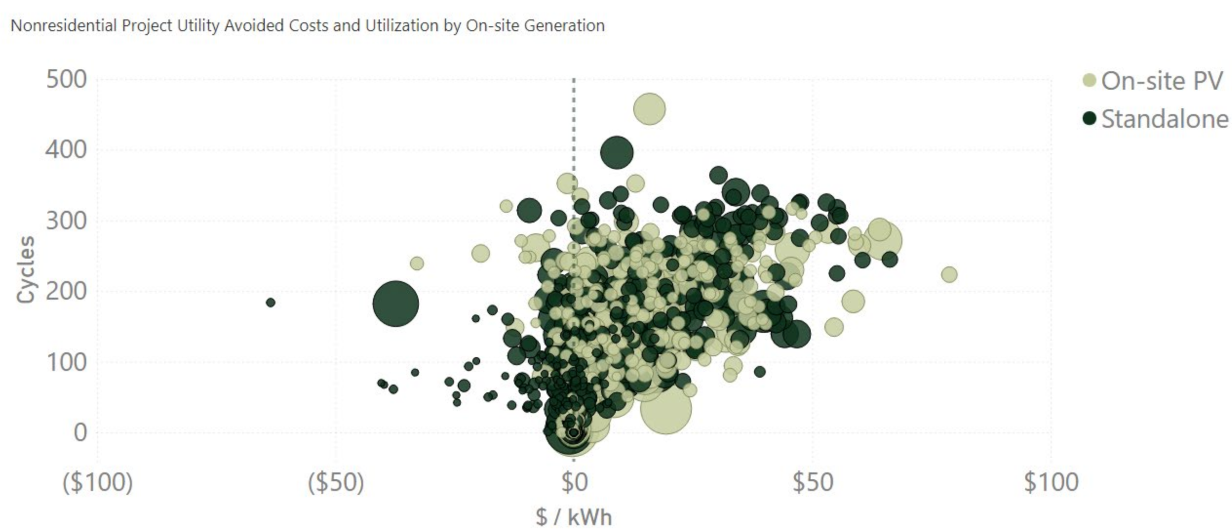


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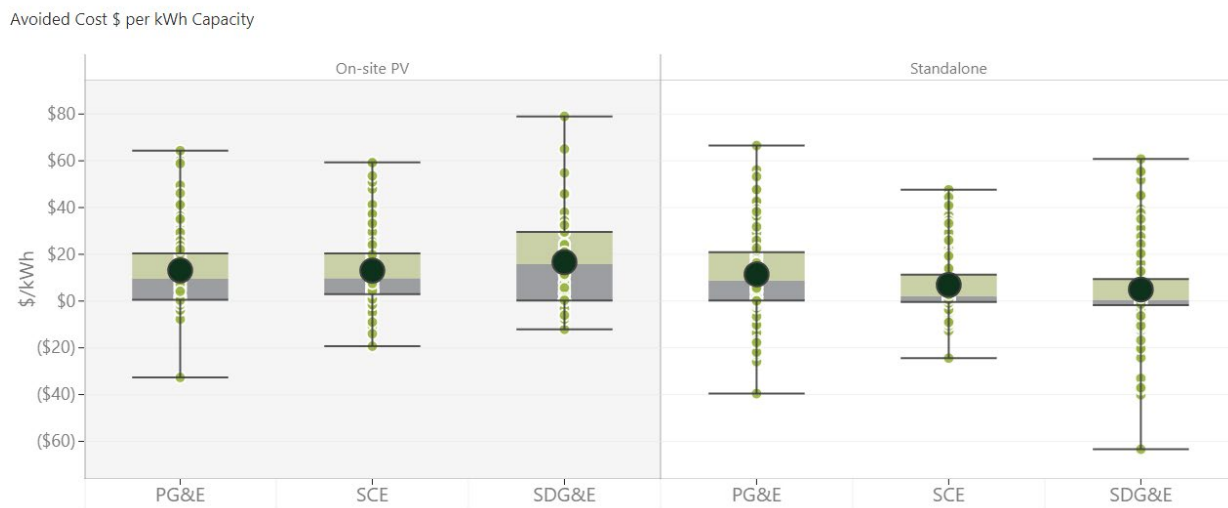
FIGURE 4-163: DISTRIBUTION OF NONRESIDENTIAL AVOIDED COSTS $ KWH BY IOU AND ON-SITE GENERATION



The timing of utility avoided cost benefit is evident in Figure 4-164 which presents how those avoided cost benefits are allocated across month during 2023 for each IOU. Again, the marginal costs modeled in this study are highest when energy prices are high, and the CAISO system load is peaking. Most of the system cost value is captured in a small number of high-cost hours that are generation capacity constrained. These hours generally align with net peak CAISO hours, which is evident with the magnitude of savings in July and August relative to other months throughout the year.

FIGURE 4-164: NONRESIDENTIAL MARGINAL AVOIDED COST $ PER CAPACITY KW BY MONTH AND IOU

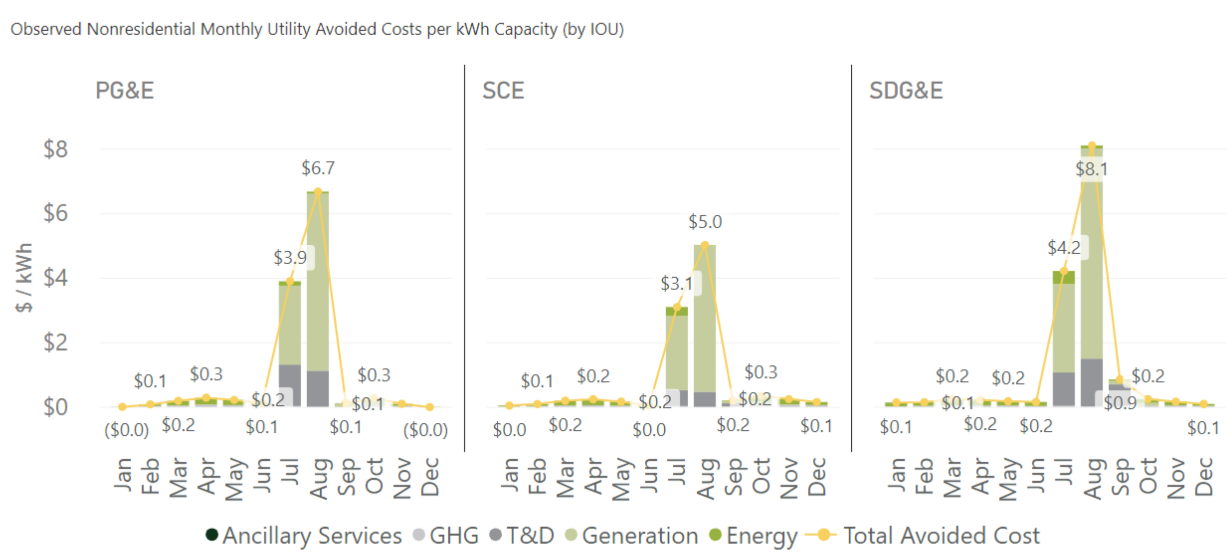
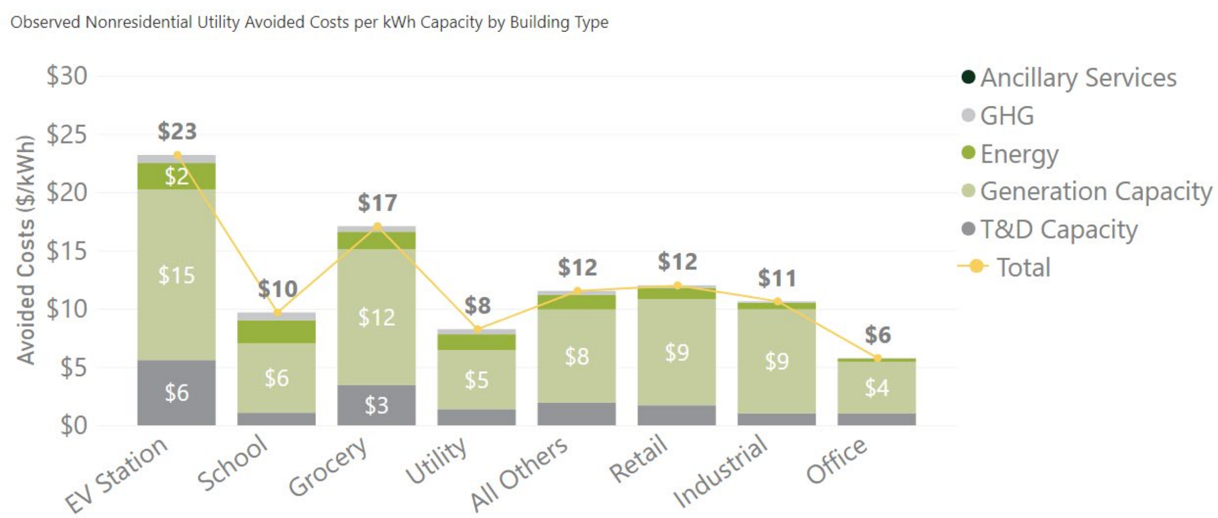


Figure 4-165 presents the average utility avoided cost benefits in $/kWh capacity by nonresidential facility type. We observed targeted discharge and greater utilization of systems installed at EV stations during on-peak hours. This discharge behavior allows for greater realized utility avoided cost benefits.

FIGURE 4-165: NONRESIDENTIAL MARGINAL AVOIDED COST $ PER CAPACITY KWH BY BUILDING TYPE

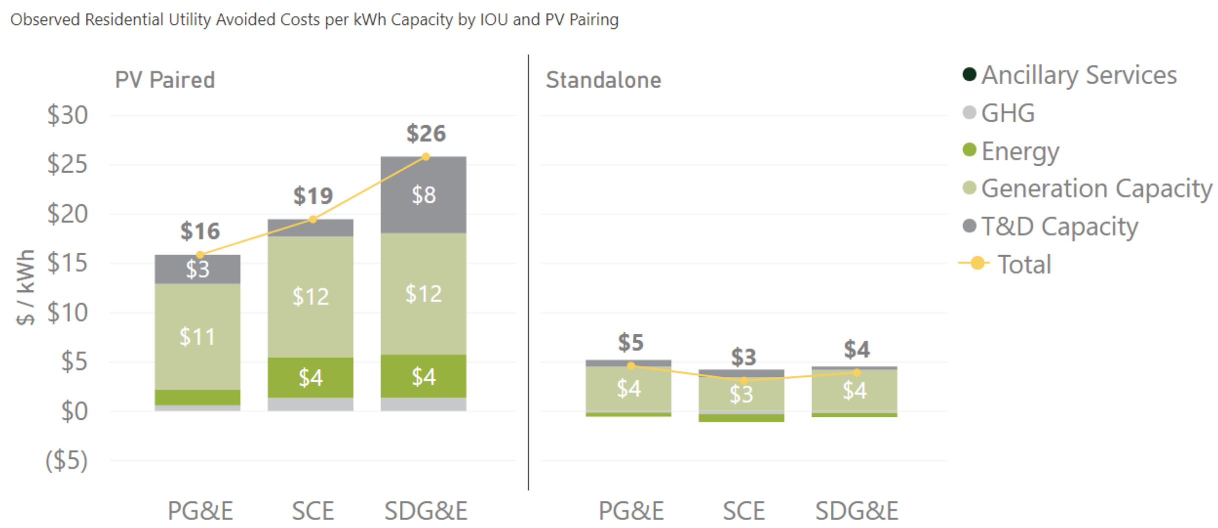


Residential Utility Avoided Costs

Prior sections of the evaluation have detailed how residential systems are being utilized for TOU arbitrage and self-consumption. When paired with on-site PV, systems are discharging exclusively on-peak or on-peak *and* to zero out delivered load. Furthermore, some systems are discharging beyond BTM consumption and exporting excess battery kWh capacity to the grid during on-peak hours. Export is standard daily practice for some groups of systems and wholly event based (ELRP, for example) for other groups.

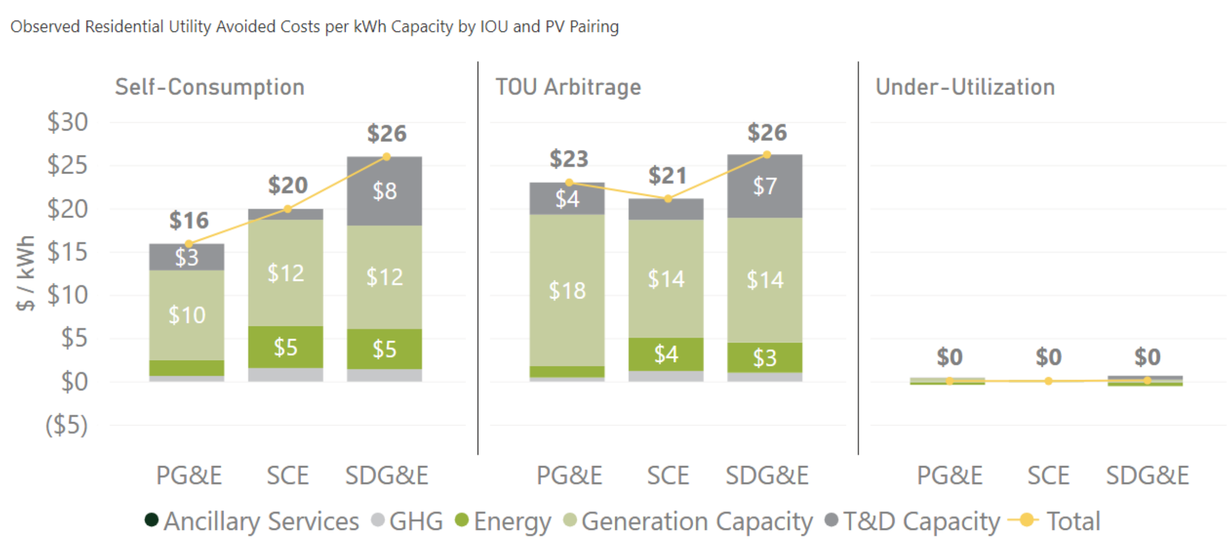
Either way, these behaviors are advantageous from a customer bill, a system load, and GHG perspective. Given the correlation between billed on-peak hours of 4pm – 9pm, CAISO net loading, and marginal grid generator emissions to utility costs, observed residential system behavior in 2023 would be advantageous from an avoided utility cost perspective as well. The normalized utility marginal costs for residential systems by electric IOU are shown in Figure 4-166. Marginal avoided costs are positive (+) and marginal incurred costs are negative (-). PV paired systems for all three utilities realized total marginal avoided cost savings during 2023 at a greater overall magnitude than standalone storage systems, when normalized by kWh capacity. Overall, the average marginal *avoided* cost (+) for PV paired residential systems in PG&E territory is $16 per capacity (kWh), for SCE they were $19 and for SDG&E they were $26 per capacity (kWh). Again, most of those cost savings come from energy, T&D and generation capacity.

FIGURE 4-166: RESIDENTIAL MARGINAL AVOIDED COST $ PER KWH CAPACITY BY IOU



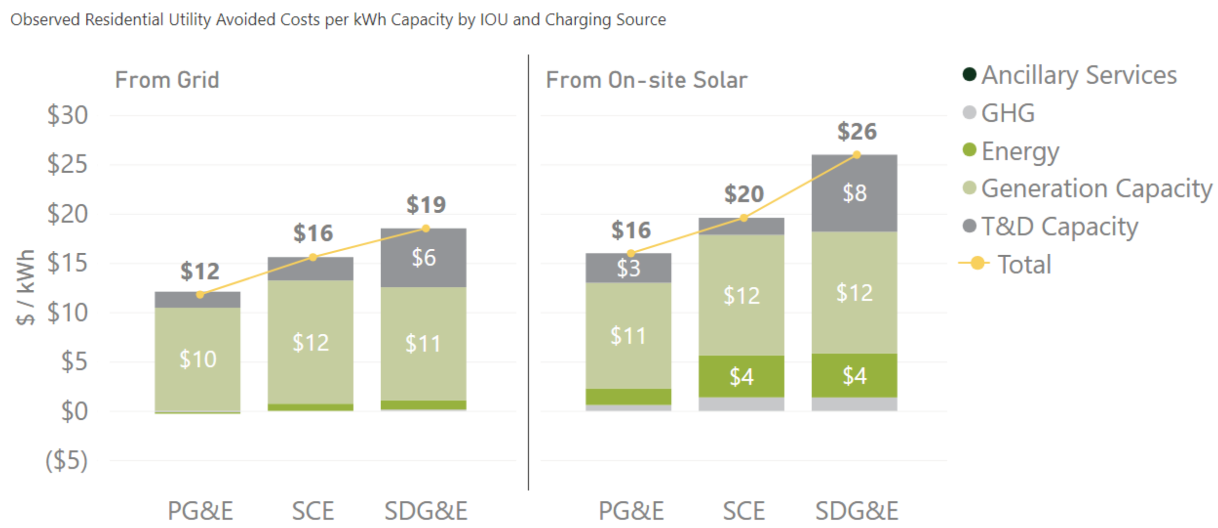
Since systems operating in self-consumption and TOU arbitrage modes are discharging on-peak, reductions in household consumption during those hours translate to avoided cost savings for each utility. Under-utilized systems provide no benefits (Figure 4-167).

FIGURE 4-167: RESIDENTIAL MARGINAL AVOIDED COST $ PER KWH CAPACITY BY IOU AND OPERATING MODE



Greater benefits are also realized for PV paired systems charging from on-site solar than similar paired systems charging from grid energy. We observed an increased benefit from the energy component of the utility avoided cost for paired systems.

FIGURE 4-168: RESIDENTIAL MARGINAL AVOIDED COST $ PER KWH CAPACITY BY IOU AND CHARGING SOURCE



The correlation between greater utilization and utility avoided cost benefits is presented for the residential sector in the scatterplot below in Figure 4-169. Almost all residential systems provided an avoided cost benefit in 2023 – independent of PV pairing or not – but the magnitude of benefit is aligned with greater system utilization.

FIGURE 4-169: RESIDENTIAL PROJECT AVOIDED COST $ PER CAPACITY KWH BY ON-SITE GENERATION

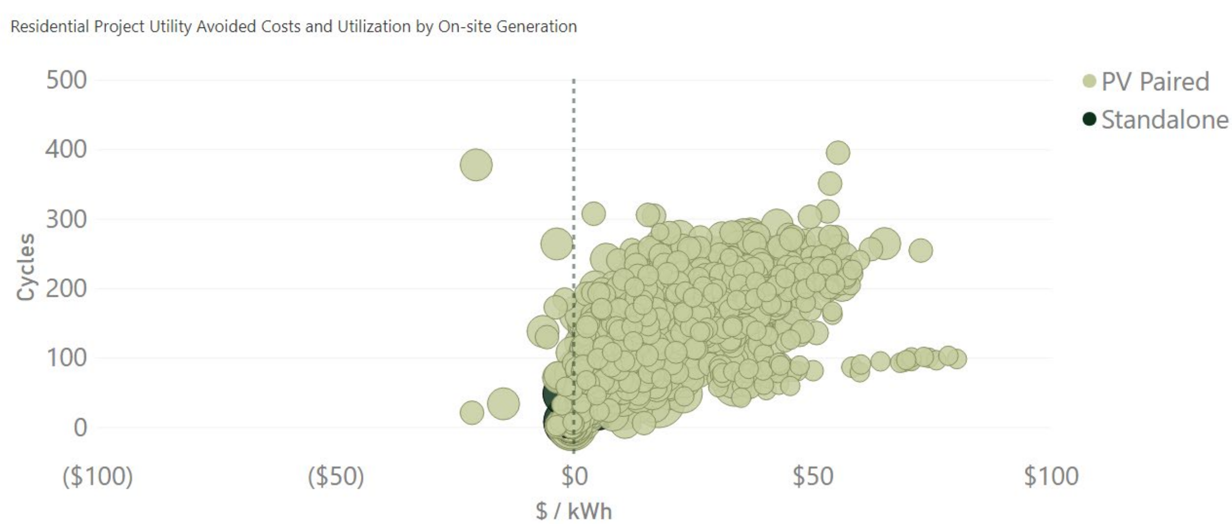
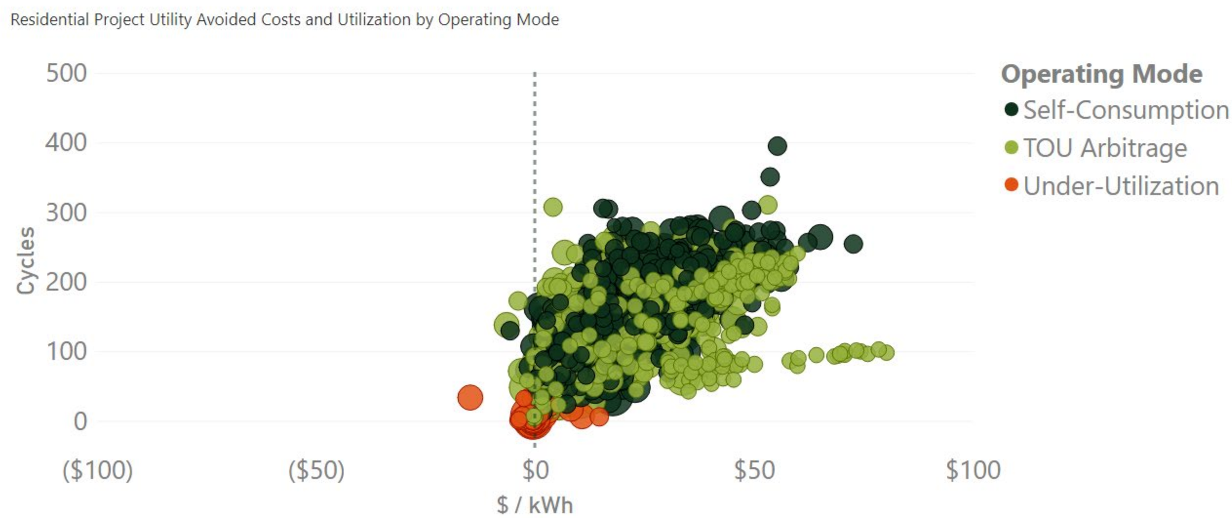
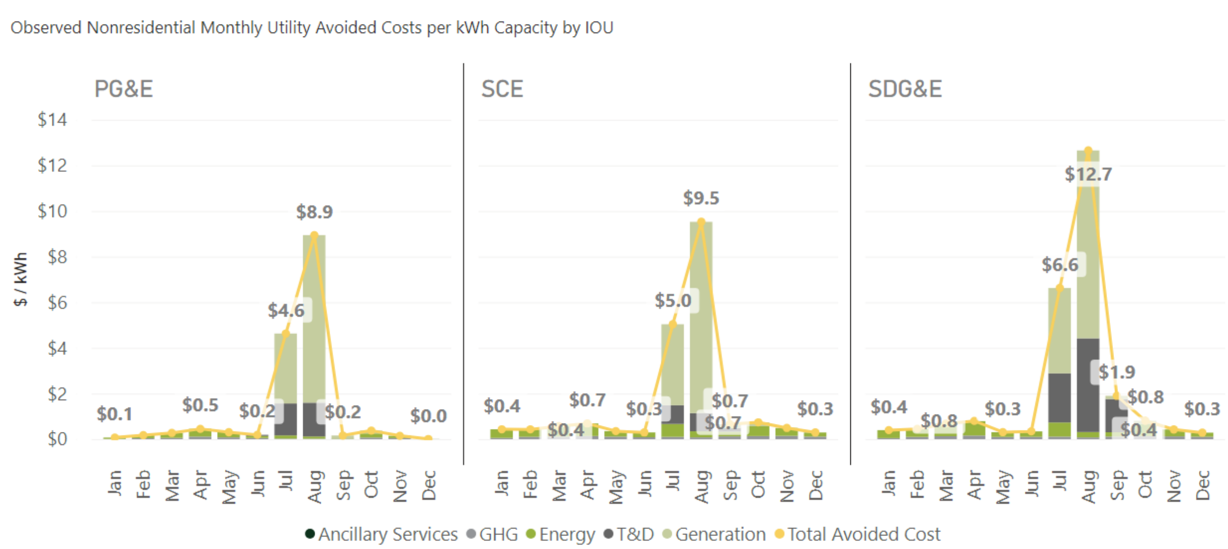


FIGURE 4-170: RESIDENTIAL PROJECT AVOIDED COST $ PER CAPACITY KWH BY OPERATING MODE



Like the nonresidential sector, utility cost benefits are really driven by storage performance during some specific costly hours. As discussed throughout this report, these systems were generally charging during low marginal cost periods and discharging in the early afternoon and evening during high utility cost and emissions periods, especially during summer months. These higher costs also align with on-peak TOU periods and, as presented below in Figure 4-171, occur throughout the year, but like nonresidential systems, the benefits accrued over capacity-constrained hours in July and August.

FIGURE 4-171: RESIDENTIAL MARGINAL AVOIDED COST $ PER CAPACITY KWH BY MONTH AND IOU



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Overall Utility Avoided Cost Summaries

Below we summarize the total avoided cost benefits (+), or cost incurred (-) during 2023 for each of the three IOUs and two customer sectors – nonresidential and residential. Average impacts by avoided cost component are also detailed along with the total. The utilization, timing and efficiency of storage charge and discharge during 2023 provided an avoided cost benefit to all three IOUs. Residential projects provided a greater benefit than nonresidential systems, on average, as a percentage of capacity kWh. We also observe some differences within each sector and across utility as well. Again, the avoided costs are driven much more substantially during a few capacity constrained hours, while other components of the avoided costs are more evenly distributed throughout the year.

FIGURE 4-172: NONRESIDENTIAL STORAGE UTILITY AVOIDED COSTS ($/KWH) BY IOU

n Prj, Ancillary Services, Energy, GHG, T&D, Generation, Total
BY ELECTRIC IOU

Electric IOU	n Prj	Ancillary Services	Energy	GHG	T&D	Generation	Total
PG&E	296	$0	$1	$0	$2	$8	$12
SCE	499	$0	$1	$0	$1	$7	$10
SDG&E	187	$0	$2	$0	$3	$9	$14
Overall	**982**	**$0**	**$1**	**$0**	**$2**	**$8**	**$11**

FIGURE 4-173: NONRESIDENTIAL STORAGE UTILITY AVOIDED COSTS ($/KWH) BY ON-SITE GENERATION

n Prj, Ancillary Services, Energy, GHG, T&D, Generation, Total
BY ON-SITE GENERATION

On-site Generation	n Prj	Ancillary Services	Energy	GHG	T&D	Generation	Total
On-site PV	377	$0	$2	$1	$2	$9	$14
Standalone	611	$0	$1	$0	$2	$7	$9
Overall	**988**	**$0**	**$1**	**$0**	**$2**	**$8**	**$11**

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FIGURE 4-174: NONRESIDENTIAL STORAGE UTILITY AVOIDED COSTS ($/KWH) BY PAYMENT YEAR

n Prj, Ancillary Services, Energy, GHG, T&D, Generation, Total
BY UPFRONT PAYMENT YEAR

Upfront Payment Year	n Prj	Ancillary Services	Energy	GHG	T&D	Generation	Total
2015	14	($0)	($0)	($0)	$1	$1	$2
2016	23	($0)	($1)	($0)	$1	$5	$5
2017	51	$0	$0	($0)	$0	$4	$4
2018	75	$0	$1	$0	$0	$5	$6
2019	227	$0	$1	$0	$1	$6	$8
2020	103	($0)	($0)	($0)	$1	$4	$5
2021	162	$0	$1	$0	$1	$7	$10
2022	180	$0	$2	$1	$3	$12	$18
2023	153	$0	$2	$0	$2	$8	$12
Overall	**988**	**$0**	**$1**	**$0**	**$2**	**$8**	**$11**

FIGURE 4-175: NONRESIDENTIAL STORAGE UTILITY AVOIDED COSTS ($/KWH) BY BUDGET CATEGORY

n Prj, Ancillary Services, Energy, GHG, T&D, Generation, Total
BY BUDGET CATEGORY

Budget Category	n Prj	Ancillary Services	Energy	GHG	T&D	Generation	Total
2017 Prior	173	$0	$0	$0	$1	$3	$4
Equity Resiliency	157	$0	$2	$0	$2	$7	$11
Large-Scale Storage	608	$0	$1	$0	$2	$9	$12
Non-Residential Storage Equity	50	$0	$2	$0	$1	$7	$11
Overall	**988**	**$0**	**$1**	**$0**	**$2**	**$8**	**$11**

FIGURE 4-176: NONRESIDENTIAL STORAGE UTILITY AVOIDED COSTS ($/KWH) BY BUILDING TYPE

n Prj, Ancillary Services, Energy, GHG, T&D, Generation, Total
BY BUILDING TYPE

Building Type	n Prj	Ancillary Services	Energy	GHG	T&D	Generation	Total
All Others	162	$0	$1	$0	$2	$8	$12
EV Station	100	$0	$2	$1	$6	$15	$23
Grocery	66	$0	$1	$0	$3	$12	$17
Industrial	142	$0	$1	$0	$1	$9	$11
Office	71	$0	$0	$0	$1	$4	$6
Retail	73	$0	$1	$0	$2	$9	$12
School	267	$0	$2	$1	$1	$6	$10
Utility	107	$0	$1	$0	$1	$5	$8
Overall	**988**	**$0**	**$1**	**$0**	**$2**	**$8**	**$11**

FIGURE 4-177: NONRESIDENTIAL STORAGE UTILITY AVOIDED COSTS ($/KWH) BY PROGRAM YEAR

n Prj, Ancillary Services, Energy, GHG, T&D, Generation, Total
BY PROGRAM YEAR

Program Year	n Prj	Ancillary Services	Energy	GHG	T&D	Generation	Total
2012	4	$0	$1	$0	$2	($0)	$3
2013	4	$0	$0	$0	$0	$0	$0
2014	55	($0)	($0)	($0)	$1	$3	$3
2015	67	$0	$0	$0	$0	$4	$5
2016	43	$0	$0	$0	$0	$2	$3
2017	320	$0	$1	$0	$1	$5	$8
2018	59	($0)	($0)	($0)	$0	$4	$5
2019	79	$0	$1	$0	$2	$7	$9
2020	304	$0	$2	$1	$3	$11	$16
2021	49	$0	$2	$1	$1	$8	$12
2022	4	$0	$1	$0	$0	$5	$7
Overall	**988**	**$0**	**$1**	**$0**	**$2**	**$8**	**$11**

FIGURE 4-178: RESIDENTIAL STORAGE UTILITY AVOIDED COSTS IMPACTS ($/KWH) BY IOU

n Prj, Ancillary Services, Energy, GHG, T&D, Generation, Total
BY ELECTRIC IOU

Electric IOU	n Prj	Ancillary Services	Energy	GHG	T&D	Generation	Total
PG&E	1046	$0	$2	$1	$3	$11	$16
SCE	614	$0	$4	$1	$2	$12	$19
SDG&E	299	$0	$4	$1	$8	$12	$26
Overall	**1959**	**$0**	**$3**	**$1**	**$3**	**$11**	**$18**

FIGURE 4-179: RESIDENTIAL STORAGE UTILITY AVOIDED COSTS ($/KWH) BY ON-SITE GENERATION

n Prj, Ancillary Services, Energy, GHG, T&D, Generation, Total
BY ON-SITE PV

On-Site PV	n Prj	Ancillary Services	Energy	GHG	T&D	Generation	Total
PV Paired	2055	$0	$3	$1	$3	$11	$18
Standalone	22	($0)	($1)	($0)	$1	$4	$4
Overall	**2077**	**$0**	**$3**	**$1**	**$3**	**$11**	**$18**

FIGURE 4-180: RESIDENTIAL STORAGE UTILITY AVOIDED COSTS IMPACTS ($/KWH) BY PAYMENT YEAR

n Prj, Ancillary Services, Energy, GHG, T&D, Generation, Total
BY PAYMENT YEAR

Payment Year	n Prj	Ancillary Services	Energy	GHG	T&D	Generation	Total
2018	98	$0	$3	$1	$4	$16	$24
2019	187	$0	$3	$1	$4	$16	$24
2020	274	$0	$3	$1	$3	$11	$19
2021	734	$0	$2	$1	$3	$10	$16
2022	529	$0	$3	$1	$3	$11	$18
2023	255	$0	$3	$1	$3	$10	$17
Overall	**2077**	**$0**	**$3**	**$1**	**$3**	**$11**	**$18**

FIGURE 4-181: RESIDENTIAL STORAGE UTILITY AVOIDED COSTS IMPACTS ($/KWH) BY BUDGET CATEGORY

n Prj, Ancillary Services, Energy, GHG, T&D, Generation, Total
BY BUDGET CATEGORY

Budget Category	n Prj	Ancillary Services	Energy	GHG	T&D	Generation	Total
All Others	2	$0	$5	$1	$2	$15	$24
Equity Resiliency	567	$0	$2	$1	$3	$10	$16
Large-Scale Storage	104	$0	$2	$1	$3	$10	$16
Small Residential Storage	1404	$0	$3	$1	$4	$12	$20
Overall	**2077**	**$0**	**$3**	**$1**	**$3**	**$11**	**$18**

FIGURE 4-182: RESIDENTIAL STORAGE UTILITY AVOIDED COSTS IMPACTS ($/KWH) BY PROGRAM YEAR

n Prj, Ancillary Services, Energy, GHG, T&D, Generation, Total
BY PROGRAM YEAR

Program Year	n Prj	Ancillary Services	Energy	GHG	T&D	Generation	Total
2017	96	$0	$4	$1	$4	$13	$22
2018	204	$0	$3	$1	$4	$16	$25
2019	225	$0	$3	$1	$3	$10	$16
2020	886	$0	$2	$1	$3	$10	$17
2021	428	$0	$3	$1	$3	$11	$18
2022	185	$0	$3	$1	$3	$13	$20
2023	53	$0	$2	$1	$2	$10	$15
Overall	**2077**	**$0**	**$3**	**$1**	**$3**	**$11**	**$18**

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FIGURE 4-183: RESIDENTIAL STORAGE UTILITY AVOIDED COSTS IMPACTS ($/KWH) BY OPERATING MODE

n Prj, Ancillary Services, Energy, GHG, T&D, Generation, Total
BY OPERATING MODE

Operating Mode	n Prj	Ancillary Services	Energy	GHG	T&D	Generation	Total
Other/Unknown	16	$0	$0	$0	$1	$3	$4
Self-Consumption	1323	$0	$3	$1	$4	$11	$18
TOU Arbitrage	617	$0	$3	$1	$3	$15	$22
Under-Utilization	121	($0)	($0)	($0)	$0	$0	$0
Overall	**2077**	**$0**	**$3**	**$1**	**$3**	**$11**	**$18**

FIGURE 4-184: RESIDENTIAL STORAGE UTILITY AVOIDED COSTS ($/KWH) BY CHARGING SOURCE

n Prj, Ancillary Services, Energy, GHG, T&D, Generation, Total
BY BATTERY CHARGING, ON-SITE PV

On-Site PV	Battery Charging	n Prj	Ancillary Services	Energy	GHG	T&D	Generation	Total
PV Paired	From Grid	58	$0	$0	($0)	$2	$11	$14
Standalone	From Grid	22	($0)	($1)	($0)	$1	$4	$4
PV Paired	From On-site Solar	1997	$0	$3	$1	$3	$11	$18
Overall		**2077**	**$0**	**$3**	**$1**	**$3**	**$11**	**$18**

4.5.2 Generation

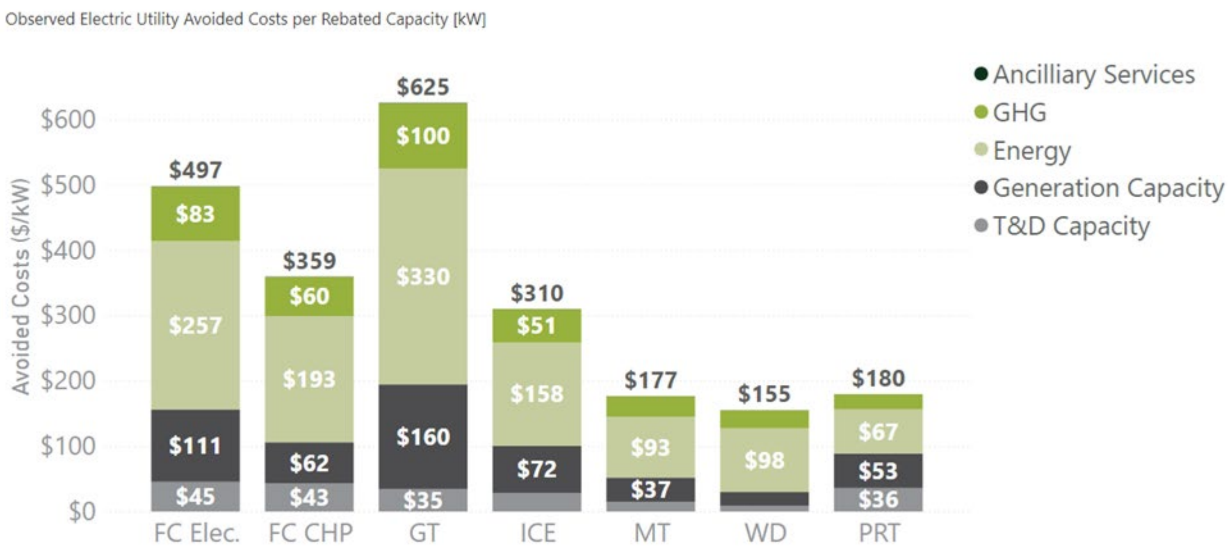
Marginal utility cost rates ($/kWh) described previously were combined with observed hourly electricity generation profiles in calculations of avoided costs for generation systems. Results are shown below in Figure 4-185 by IOU, on an avoided cost per incentivized kW basis. SDG&E realized the highest avoided costs per incentivized kW, achieving $483 per incentivized kW. PG&E saw avoided costs of $407 per incentivized kW, and SCE saw $399 per incentivized kW in 2023. SDG&E T&D capacity costs were higher than average, while SCE Generation Capacity costs were higher than the other utilities. Avoided costs are higher for generation technologies than for storage projects in part because these are electric utility avoided costs only. For generation projects, a complete benefit-cost analysis would be required to account for changes in gas utility costs. Higher capacity factors of generation projects also contribute to differences in avoided costs per unit of capacity.

FIGURE 4-185: OBSERVED GENERATION SYSTEM 2023 UTILITY AVOIDED COSTS BY IOU ($ PER REBATED KW)

Note: Ancillary Services make up a very small percentage of the overall avoided costs and are not noticeable in the graphic.

When reviewing the observed utility marginal avoided costs by technology type, as shown below in Figure 4-186, the Gas Turbines avoid the highest total marginal avoided costs per capacity, at over $625/kW, while Microturbines and Wind Turbines were observed to avoid the fewest marginal costs. Differences in utilization are the most important factor explaining differences in these avoided costs. The distribution of projects across electric utility service areas is another factor. Lastly, avoided electric utility costs are reported only for PG&E, SCE, and SDG&E. Avoided electric utility costs are not reported for projects installed by SGIP participants receiving electric service from some other provider (e.g., LADWP). Consequently, different groups of projects may contribute to calculation of avoided cost results and observed capacity factors.

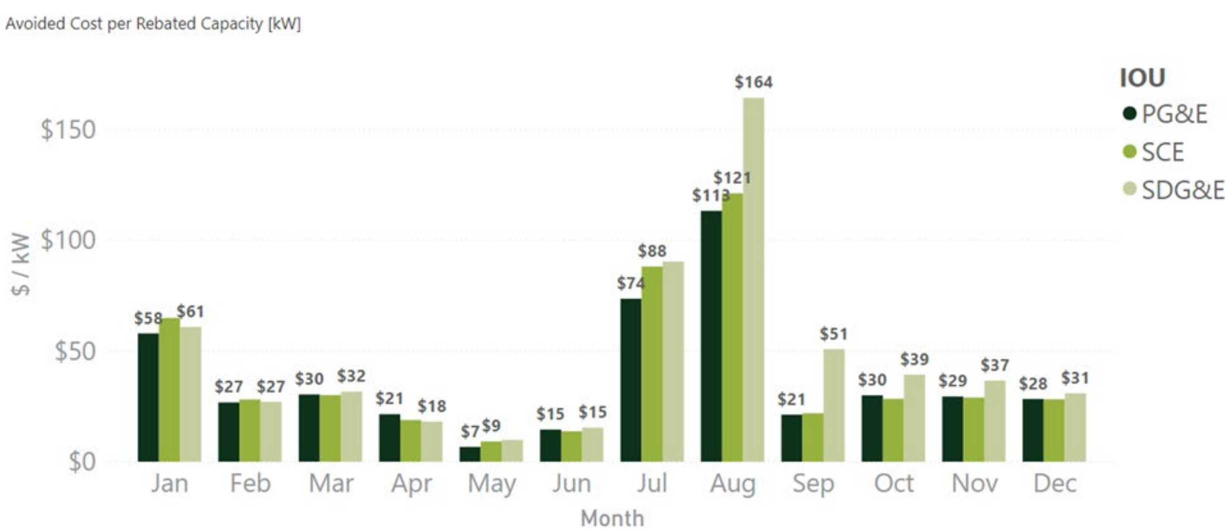
FIGURE 4-186: OBSERVED GENERATION SYSTEM 2023 UTILITY AVOIDED COSTS BY TECHNOLOGY TYPE ($ PER REBATED KW)



Note: Ancillary Services make up a very small percentage of the overall avoided costs and are not noticeable in the graphic.

Figure 4-187 shows the avoided cost rate, per incentivized capacity, by month during 2023. August saw some of the highest avoided cost rates, especially for SDG&E, topping over $160 per incentivized kW, while the rest of the year the rates were mostly under $40/kW.

FIGURE 4-187: OBSERVED GENERATION SYSTEM 2023 UTILITY AVOIDED BY IOU AND MONTH



Utility Avoided Cost Summaries

Below we summarize the total avoided cost benefits throughout 2023 for each of the three IOUs, by equipment type, and by fuel type. All generation systems were found to produce avoided cost benefits. Average impacts by avoided cost component are also detailed along with the total. Gas Turbines showed the greatest avoided costs, driven by the generation and energy components, which also drove the SDG&E and SCE avoided costs higher. Non-renewably fueled systems also saw higher avoided costs than renewable systems due to the large amount of generation from these systems.

FIGURE 4-188: SUMMARY OF 2023 GENERATION UTILITY AVOIDED COSTS IMPACTS ($/KW)

Utility	n Proj	Anc Srvcs	Energy	GHG	Generation	T&D	Total
PG&E	121	$0	$213	$71	$86	$37	$407
SCE	95	$0	$216	$65	$96	$22	$399
SDG&E	26	$0	$228	$69	$94	$92	$483
Overall	**242**	**$0**	**$215**	**$68**	**$92**	**$33**	**$408**

FIGURE 4-189: SUMMARY OF 2023 GENERATION UTILITY AVOIDED COSTS IMPACTS BY TECHNOLOGY TYPE ($/KW)

Equipment Type	n Proj	Anc Srvcs	Energy	GHG	Generation	T&D	Total
FC CHP	5	$0	$193	$60	$62	$43	$359
FC Elec.	188	$0	$258	$83	$111	$45	$497
GT	1	$1	$330	$100	$160	$35	$625
ICE	19	$0	$158	$51	$72	$28	$310
MT	6	$0	$93	$31	$37	$15	$177
PRT	6	$0	$67	$23	$53	$36	$180
WD	17	$0	$98	$28	$21	$9	$155
Overall	**242**	**$0**	**$215**	**$68**	**$92**	**$33**	**$408**

FIGURE 4-190: SUMMARY OF 2023 GENERATION UTILITY AVOIDED COSTS BY FUEL TYPE ($/KW)

Fuel Type	n Proj	Anc Srvcs	Energy	GHG	Generation	T&D	Total
Non-Renewable	93	$0	$252	$85	$108	$47	$492
Other	13	$0	$122	$39	$33	$12	$206
Renewable	15	$0	$234	$80	$101	$42	$457
Overall	**121**	**$0**	**$213**	**$71**	**$86**	**$37**	**$407**

4.6 POPULATION IMPACTS

The previous sections presented the analyses conducted to showcase the impacts of sampled generation and energy storage systems. These analyses were intended to highlight how SGIP systems were behaving in 2023 and how they were performing to meet program objectives. These analyses were all based on sampled systems from a larger population of SGIP systems. In this section, metered data from the sample of projects were used to estimate population total impacts for 2023.

Appendix C provides more detail into how each of these samples were developed, but they are summarized below in Table 4-8 and Table 4-9. Overall, our team evaluated 3,289 energy storage systems (745 MWh of total energy storage capacity) and 305 generation systems (241 MW of total program generation capacity) receiving upfront payments prior to January 1st of 2024. The energy storage sample represents 7% of the total population by project count and 43% of the total population capacity, with the generation sample representing 78% of project count and 73% of the rebated capacity. Large nonresidential storage systems and residential storage systems represent the most significant percentage of the population – in terms of capacity – and have the greatest influence on overall SGIP storage population impacts, whereas all-electric fuel cells and gas turbines represent the greatest influence on generation population impacts.

TABLE 4-8: SAMPLE COMPOSITION OF 2023 SGIP STORAGE POPULATION BY CUSTOMER SECTOR

Customer Sector	Sample n	Population N	% of Projects Sampled	Sample Capacity (MWh)	Population Capacity (MWh)	% of Capacity Sampled
Nonresidential	1,211	1,560	78%	701	882	79%
Residential	2,077	44,297	5%	43	844	5%
Total	**3,289**	**45,857**	**7%**	**745**	**1,727**	**43%**

TABLE 4-9: SAMPLE COMPOSITION OF 2023 SGIP GENERATION POPULATION BY TECHNOLOGY TYPE

Technology Type	Sample n	Population N	% of Projects Sampled	Sample Capacity [MW]	Population Capacity [MW]	% of Capacity Sampled
Fuel Cell Electric	223	238	94%	85	93	91%
Fuel Cell CHP	16	19	84%	11	14	81%
Gas Turbine	4	8	50%	77	99	78%
Internal Combustion Engine	29	51	57%	27	57	48%
Microturbine	9	18	50%	6	15	47%
Wind	17	21	81%	33	33	100%
Pressure Reduction Turbine	6	9	67%	2	3	70%
Waste Heat to Power	1	1	100%	0	0	100%
Total	**305**	**365**	**78%**	**241**	**312**	**73%**

*Sampled projects includes decommissioned projects

Below we summarize the population estimates for several program impact metrics. Population project counts are also reported in the tables. Population estimates were calculated for the following in 2023:

- Electric energy – total energy generated or charged & discharged, capacity factors, and electrical and system efficiencies or overall roundtrip efficiency
- CAISO system peak demand – total CAISO top hour impacts and total top 100-hour impacts
- Environmental Impacts – total GHG impacts
- Utility Avoided Costs – total utility avoided costs

TABLE 4-10: 2023 STORAGE POPULATION ELECTRIC ENERGY IMPACTS

Customer Sector	Population N	Population Discharge (MWh)	Population Charge (MWh)	Population Net Discharge (MWh)	Population RTE
Nonresidential	1,560	94,231	112,486	-18,255	84%
Residential	44,297	5,498	6,446	-948	85%
Total	**45,857**	**99,729**	**118,932**	**-19,203**	**84%**

TABLE 4-11: 2023 GENERATION POPULATION ELECTRIC ENERGY IMPACTS

Technology Type	Population N	Population Generation [GWh]	Population CF	Population Electrical Efficiency	Population System Efficiency
Fuel Cell Electric	238	531	72.5%	48.0%	48.0%
Fuel Cell CHP	19	57	37.7%	37.4%	49.3%
Gas Turbine	8	689	67.5%	34.8%	77.9%
Internal Combustion Engine	51	263	45.1%	31.5%	52.6%
Microturbine	18	59	45.4%	25.8%	35.9%
Wind	21	72	33.1%	--	--
Pressure Reduction Turbine	9	5	18.2%	--	--
Waste Heat to Power	1	0	--	--	--
Total	**365**	**1677**	**61.6%**	**40.1%**	**44.6%**

CAISO system peak demand impacts are summarized in Table 4-12 and Table 4-13 for the gross and net top hours. In 2023 the CAISO statewide system gross load peaked at over 44,000 MW on August 16th. The CAISO peaked, from a net load perspective, on August 15th. SGIP generation projects provided a peak hour benefit by generating 137 MW of power during the CAISO Gross peak hour, and 124 MW of power during the CAISO Net peak hour.

Note that the project count below is less than the total population (as indicated in the table above). This estimate is based on all systems that were conducting normal operations during the peak hours in 2023.

TABLE 4-12: 2023 ENERGY STORAGE CAISO SYSTEM PEAK DEMAND IMPACTS (GROSS AND NET PEAK HOUR)

Customer Sector	Population N	Population Gross Peak Hour Net Discharge [MWh]	Population Net Peak Hour Net Discharge [MWh]
Nonresidential	1,560	44.5	39.9
Residential	44,297	51.8	51.4
Total	45,857	96.3	91.4

TABLE 4-13: 2023 GENERATION CAISO SYSTEM PEAK DEMAND IMPACTS (GROSS AND NET PEAK HOUR)

Technology Type	Population N	Population Gross Peak Hour Generation [MW]	Population Net Peak Hour Generation [MW]
Fuel Cell Electric	212	60.13	60.16
Fuel Cell CHP	14	3.09	2.05
Gas Turbine	51	84.87	38.95
Internal Combustion Engine	51	36.83	35.95
Microturbine	18	8.38	8.04
Wind	15	4.54	4.83
Pressure Reduction Turbine	9	0.88	0.92
Waste Heat to Power	1	0	0
Total	**328**	**198.72**	**150.254**

The total impacts across the top 100 gross and net CAISO hours are presented below in Table 4-14 and Table 4-15. In some cases, the system count is greater across the top 100 hours because some systems began normal operations and received their upfront payment after the peak hour had passed but there were still some top 100 hours left in the year.

TABLE 4-14: 2023 ENERGY STORAGE CAISO SYSTEM PEAK DEMAND IMPACTS (TOP 100 GROSS AND NET HOURS)

Customer Sector	Population N	Population Gross Top 100 Hour Net Discharge [MWh]	Population Net Top 100 Hour Net Discharge [MWh]
Nonresidential	1,560	30	30
Residential	44,297	37	38
Total	45,857	67	**68**

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TABLE 4-15: 2023 GENERATION CAISO SYSTEM PEAK DEMAND IMPACTS (TOP 100 GROSS AND NET HOURS)

Technology Type	Population N	Population Average Gross Top 100 Hour Generation [MWh]	Population Average Net Top 100 Hour Generation [MWh]
Fuel Cell Electric	213	59.13	59.6
Fuel Cell CHP	15	5.74	5.7
Gas Turbine	8	76.54	76.2
Internal Combustion Engine	51	34.34	34.3
Microturbine	18	7.13	7.3
Wind	15	4.72	4.4
Pressure Reduction Turbine	9	0.86	0.8
Waste Heat to Power	1	0	0
Total	**330**	**188.45**	**188.3**

Greenhouse gas impacts during 2023 are summarized in Table 4-16 and Table 4-17. Positive greenhouse gas impacts reflect increased emissions. The magnitude and sign of greenhouse gas impacts are dependent on the timing of charge and discharge for storage systems. For generation systems, the magnitude and sign of impacts have more to do with the fuel type and baseline type, as renewably fueled systems tend to reduce emissions, and systems with vented baselines reduce emissions significantly more than flared baselines.

Both the residential and nonresidential energy storage sectors contributed to a decrease in GHG emissions in 2023. This was largely an effect of charging systems from on-site PV generation in morning hours when marginal emissions were lower than afternoon and evening hours (Section 4.4.1). Systems were either trying to maintain zero net load during these higher marginal emission hours or responding to TOU price signals. On average, residential systems decreased GHG emissions by roughly 17.3 kg/kWh and nonresidential systems decreased emissions by roughly 5.1 kg/kWh.

TABLE 4-16: 2023 ENERGY STORAGE POPULATION GREENHOUSE GAS IMPACTS

Customer Sector	N	Population Impact (MT CO_2)	Capacity MWh	MT / Capacity MWh
Nonresidential	1,560	-4,663	882	-5.1
Residential	44,297	-14,127	844	-17.3
Total	45,857	-18,791	1,727	-11.1

TABLE 4-17: 2023 GENERATION POPULATION GREENHOUSE GAS IMPACTS

Technology Type	Fuel Type	Baseline Type	Population N	Population GHG Impact [MT CO_{2eq}]	GHG Impact Rate [MT CO_{2eq}/MWh]
Fuel Cell Electric	Renewable Gas	Flare	1	-120	-0.36
		Vent	1	-21,634	-3.36
	Non-Renewable Gas	N/A	236	32,663	0.18
Fuel Cell CHP	Renewable Gas	Flare	2	-5,967	-0.30
	Non-Renewable Gas	N/A	17	4,277	0.11
Gas Turbine	Renewable Gas	Flare	1	-39,132	-0.50
	Non-Renewable Gas	N/A	7	-13,185	-0.02
Internal Combustion Engine	Renewable Gas	Flare	26	-60,342	-0.41
		Vent	7	-99,138	-5.40
	Non-Renewable Gas	N/A	18	13,309	0.14
Microturbine	Renewable Gas	Flare	7	-2,217	-0.34
	Non-Renewable Gas	N/A	9	12,643	0.31
	Other	Flare	2	-2,791	-0.42
Wind	Other	N/A	21	-22,925	-0.34
Pressure Reduction Turbine	Other	N/A	9	-1,678	-0.32
Waste Heat to Power	Other	N/A	1	0	0
Total	--	--	**365**	**-206,237**	**-0.12**

Utility marginal cost impacts during 2023 are summarized in Table 4-18 and Table 4-19. The evaluation found SGIP incentivized energy storage systems provided a utility-level population benefit of almost $23 million in avoided costs across both storage sectors, while generation systems provided utility-level population benefits of over $100 million. These results are consistent with the analyses presented in Section 4.5.1. Nonresidential and residential storage systems were generally discharging during hours that were capacity or distribution constrained, especially during the summertime, while generation systems typically provided a baseload that didn't vary much throughout the day or year. On average, nonresidential storage systems provided a benefit in avoided cost of roughly $10/kWh and residential storage systems provided a benefit of $17/kWh, while generation systems provided a benefit in avoided cost between $193 per rebated kW capacity for wind turbines to $908 per rebated capacity for gas turbines.

TABLE 4-18: 2023 ENERGY STORAGE UTILITY MARGINAL COST IMPACTS

Customer Sector	Population N	Population Impact (Avoided Cost $)
Nonresidential	1,560	$8,655,022
Residential	44,297	$14,118,017
Total	**45,857**	**$22,773,039**

TABLE 4-19: 2023 GENERATION UTILITY MARGINAL COST IMPACTS

Technology Type	Population N	Population Impact (Avoided Cost $)
Fuel Cell Electric	238	$36,697,294
Fuel Cell CHP	19	$3,651,128
Gas Turbine	8	$30,022,134
Internal Combustion Engine	51	$21,264,164
Microturbine	18	$3,561,547
Wind	21	$5,438,454
Pressure Reduction Turbine	9	$552,783
Waste Heat to Power	1	$0
Total	**365**	**$101,187,505**

5 RESIDENTIAL STORAGE OPTIMIZATION

Previous sections have revealed how the performance and utilization of residential energy storage systems contributed to decreases in greenhouse gas (GHG) emissions and utility costs, while providing bill savings to host customers in 2023. Residential energy storage systems are generally conducting 1) self-consumption, 2) TOU arbitrage without export, 3) TOU arbitrage with export – either regularly or exclusively throughout specific times like a demand response event, or 4) some combination of all. We observe residential PV paired systems discharging, on average, 42% of system capacity daily during summer months and many residential customers are limiting discharge to maintain net zero load rather than exporting. This finding is intuitive – if customers are already abiding by SGIP rules for round-trip efficiency, utilization and GHG reductions – they may also want to have reserve energy in the event of an outage. Furthermore, frequent full discharge cycling may not be advantageous from battery engineering, effective useful life, or warranty perspective.

Storage project developers and host customers may not be aware of system-level peak hours, energy prices, or marginal emissions unless they are enrolled in a demand response program or real-time pricing rate where a price signal (or incentive) encourages shifting or reducing demand. Customers understand their BTM consumption and bill rate structure, but grid-level demand may not be in their purview. The 4 pm – 9pm on-peak TOU hours provide a broad signal to arbitrage energy over a five-hour period, but emissions vary considerably during this period, narrowing the window for achievement of maximum emissions reductions. A perfectly designed energy storage system optimized to reduce GHG emissions or respond to grid emergencies would charge only during the lowest marginal emissions or utility cost periods and discharge only when marginal emissions or utility costs are at their maximum. The motivation behind this optimization analysis is to quantify the considerable untapped potential of battery capacity if deployed in response to grid needs.

Verdant has developed a simulation tool that can dispatch storage systems for optimal timing and magnitude in response to specified signals and other conditions. This tool can estimate benefits of optimized dispatch based on selected objectives, including 1) to minimize the customer's bill, 2) to minimize greenhouse gas emissions, or 3) to minimize utility costs. In this section we explore how the observed real-world performance of residential SGIP storage systems compares to simulated optimal performance for these dispatch scenarios.

Data and Methods

Verdant's optimization tool uses mixed-integer linear programming to optimally dispatch storage under assumed battery, load, and PV conditions. Battery configuration information is required for the model, including the system's total energy capacity (kWh) and its charge/discharge power capacity (kW). This information is collected from the SGIP statewide project list. The model also requires input that specifies the round-trip-efficiency (RTE) of the battery as well as the minimum state of charge (SOC) allowable for the battery. For these optimized dispatch runs we simulated systems with RTEs of 90%, which is at the high end of measured residential RTEs and is indicative of the energy losses associated with a single duty cycle. Observed residential system efficiencies range considerably based on the equipment type and overall utilization. Under-utilization can result in the accumulation of parasitic losses which can further erode the actual efficiency of the system over time.

Another important modeling constraint is not to allow the battery to discharge beyond a predetermined minimum SOC. Verdant modeled optimized dispatch to maintain a minimum SOC of 35% of its total capacity. The assumption was based on discussions with some OEMs, and – just like the RTE – can vary based on system operating mode and technology type. The model also requires specification of the battery's SOC at the beginning of the optimization horizon (e.g., January 1 at midnight). We set beginning SOC equal to the battery's minimum allowable SOC.

The model requires information on the customer's hourly interval gross consumption and PV data (if present). The customer's gross consumption was calculated from the IOU provided AMI data or developer metered load and the metered storage charge and discharge data collected for this evaluation. The customer's gross consumption (i.e., their consumption if they didn't have a battery installed) was calculated as their net load with the battery charge and discharge activity backed out. For customers with PV onsite, the hourly metered interval PV generation data provided by project developers and manufacturers was also backed out of the AMI data to determine the customer's gross consumption. Both the gross consumption and the PV generation interval data are used as inputs in the optimization model. The simulations were performed on systems with a full year of gross load and dispatch data in 2023.

The final input required for the optimization is information related to the model's objective, (i.e., the cost against which the model is minimizing). We simulated optimal dispatch against three different representations of cost; They are 1) the customer's bill, 2) greenhouse gas emissions (GHG), and 3) utility costs (UC). For simulations minimizing the customer's bill, we reviewed the historical rate selection of each customer (provided by the IOUs) and noted their selected rate on or near June 2023. The import and export costs (under NEM 2.0)[51] associated with the customer's tariff were then included in the model. Simulations that minimized greenhouse gas emissions utilized the WattTime SGIP signal marginal

[51] Some customers were likely on NEM 1.0, which has identical rates for customer import and export, whereas under NEM 2.0 the export rate is slightly less during any TOU period. Thus, NEM 1.0 customers have no economic incentive to minimize exports, while NEM 2.0 customers have a small incentive to do so. The difference between customer bills is likely small.

emissions rate for the customer's associated grid region. To minimize utility costs, we used hourly utility avoided cost values for the customer's associated utility and climate zone.

A mixed-integer linear program was used for our simulations. The simulations assume "perfect knowledge", meaning that decisions are made about the optimal dispatch over the entire optimization horizon with full knowledge of the actual load and PV generation over the entire horizon. In reality, PV and customer load can be forecasted ahead of time, and the GHG signal is forecasted by WattTime for the next 72 hours, but none of these are known exactly on a day-ahead basis. For this reason, we modeled each day individually to replicate real-world conditions more closely. For customer bill scenarios where customers were on a tiered rate, the scenarios were modeled at the monthly level.

In our simulations, we limited the battery so that it could only charge from energy generated by the on-site PV. In cases with no PV on-site the battery was allowed to charge directly from the grid, however exports were not allowed.

Results

Throughout this section, we will present comparisons of optimal and actual observed battery dispatch. Note that the observed dispatch results presented here will differ from the avoided utility costs, avoided GHG emissions, and customer bill savings presented in previous sections of this report. The results shown here are exclusive to projects included in our optimization modeling. Projects were dropped from the optimization modeling sample for several reasons, including lack of information on the customer's rate along with quality control of the simulation results. The results presented in this section are meant to be used for directional purposes and are not intended to be taken as a final reporting of avoided utility costs, reduced GHG emissions, or customer bill savings.

The following figures (Figure 5-1, Figure 5-2, and Figure 5-3) below show the average avoided utility costs, reduced GHG emissions, and customer bill savings of the three optimal scenario types (Optimal Avoided Utility Cost, Optimal GHG, and Optimal Bills) compared with actual dispatch. The bars on each chart represent actual dispatch or the three optimal scenarios.

Figure 5-1 below shows that optimizing dispatch for utility costs has the potential to reduce utility costs by four times the reductions achieved by the actual dispatch ($80 versus $18 per kWh of battery capacity). Interestingly, we also find that optimizing for GHG reduction and customer bill savings could reduce utility costs further than actual dispatch (with increased reductions of 51% and 54%, respectively).

FIGURE 5-1: 2023 AVOIDED UTILITY COSTS FOR ACTUAL AND OPTIMAL DISPATCH SCENARIOS ($ PER KWH)

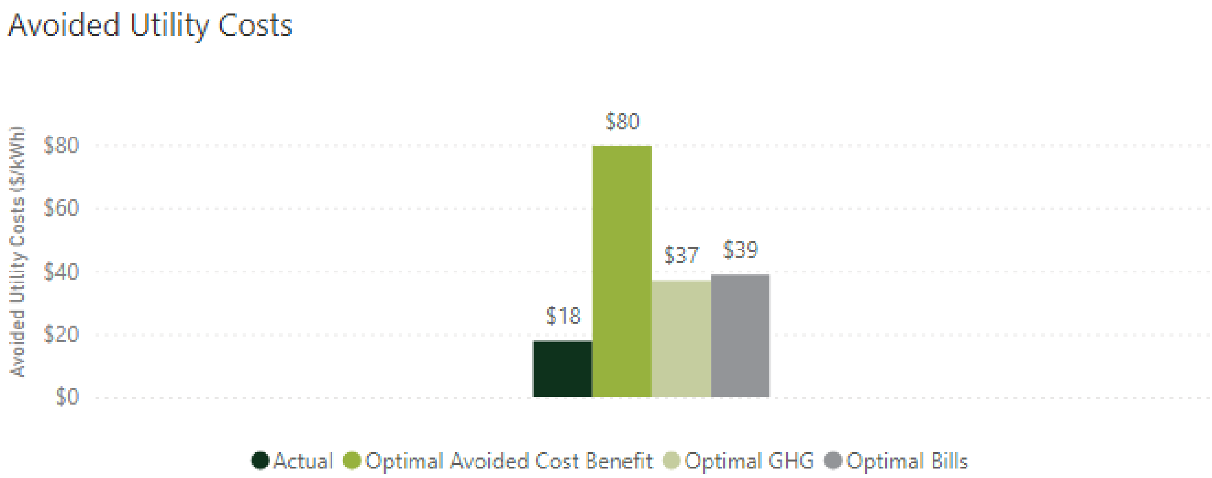

Figure 5-2 below shows that optimizing for GHG emissions has the potential to reduce GHG emissions by 65 kg per kWh of capacity (more than 3 times the reduction achieved by actual dispatch). Notably, optimizing for utility costs achieves nearly the same amount of GHG reduction as the optimal GHG scenario (62 kg per kWh of capacity). The scenario which optimizes customer bills also achieves higher GHG emission reductions than actual dispatch (31 kg/kWh and 17 kg/kWh, respectively).

FIGURE 5-2: 2023 EMISSIONS REDUCTION FOR ACTUAL AND OPTIMAL DISPATCH SCENARIOS (KG CO2 PER KWH)

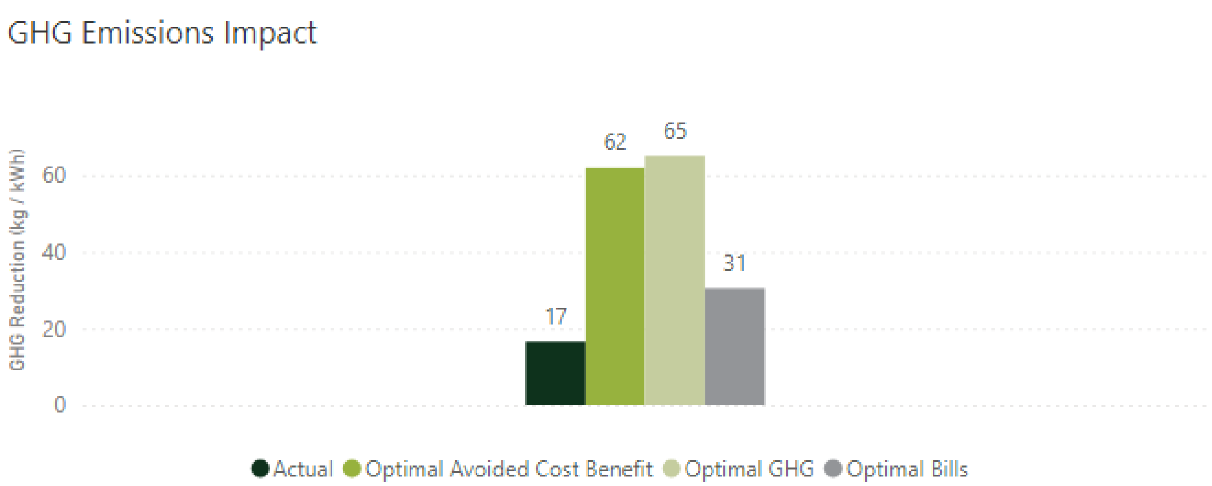

Figure 5-3 below shows that bill optimization can reduce customer bills by $22 per kWh of capacity (41% higher savings than the actual dispatch). Both the optimal utility avoided cost and optimal GHG scenarios deliver reduced customer bill savings compared to the actual dispatch.

FIGURE 5-3: 2023 CUSTOMER BILL SAVINGS FOR ACTUAL AND OPTIMAL DISPATCH SCENARIOS ($ PER KWH)

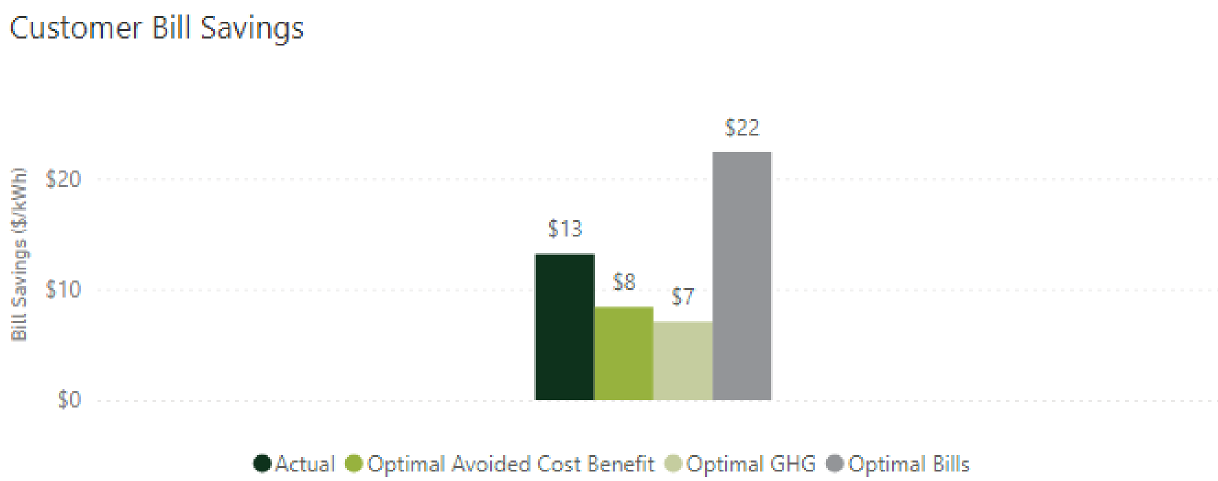

Figure 5-4 following presents a heatmap of the average hourly charge and discharge pattern for each hour of the day by month. The figure shows battery dispatch activity for the actual dispatch, followed by the dispatch activity for the optimal utility avoided cost scenario, the optimal GHG scenario, and finally the optimal customer bill scenario. These figures highlight that each optimal scenario charges and discharges more completely than the actual dispatch during charging and discharging hours. In addition, the charging profiles are virtually identical between utility cost and GHG-optimized scenarios, while discharge patterns are very similar between those two scenarios.

On average, actual system discharge never exceeds 6% of capacity in any given month-hour, while the optimal scenarios discharge 24 to 26% of capacity in their peak discharge month-hours. Similarly, the actual dispatch never charges more than 10% of capacity in any given month-hour, while the optimal scenarios charge up to 16% of capacity in a single month-hour. When comparing the hours of the day that the battery typically discharges, the optimal customer bill scenario is most like actual, with most of the discharge activity occurring between 4pm and 9pm. Both the optimal customer bill scenario and the actual dispatch also maintain relatively uniform hourly dispatch patterns throughout the year. In contrast, the optimal avoided cost and optimal GHG scenarios vary their discharge patterns significantly from month to month (following the heterogenous nature of the avoided cost and GHG cost signals). Their dispatch patterns are like each other, with the highest discharge hours occurring May through August primarily during the 7-8pm hour.

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FIGURE 5-4: AVERAGE HOURLY DISPATCH BY MONTH FOR ACTUAL AND OPTIMAL UTILITY COSTS, OPTIMAL GHG, AND OPTIMAL CUSTOMER BILLS

Actual Hourly Discharge (+) Charge (-) kWh / kWh Capacity

month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	0%	0%	0%	0%	0%	0%	0%	-0%	-2%	-4%	-6%	-6%	-5%	-3%	-1%	0%	3%	5%	4%	3%	3%	2%	1%	1%
2	1%	0%	0%	0%	0%	0%	1%	-0%	-3%	-6%	-7%	-7%	-5%	-3%	-2%	0%	4%	5%	5%	4%	3%	2%	2%	1%
3	0%	0%	1%	1%	1%	1%	1%	-0%	-2%	-5%	-7%	-6%	-5%	-3%	-2%	-1%	2%	3%	4%	4%	4%	2%	2%	1%
4	1%	1%	1%	1%	1%	1%	1%	-0%	-3%	-7%	-9%	-8%	-5%	-3%	-1%	-0%	2%	3%	4%	4%	4%	1%	2%	2%
5	1%	1%	1%	1%	1%	1%	1%	-1%	-3%	-6%	-7%	-7%	-5%	-4%	-2%	-1%	2%	3%	4%	4%	4%	2%	2%	2%
6	1%	1%	1%	1%	1%	1%	1%	-1%	-4%	-6%	-8%	-7%	-6%	-4%	-2%	-0%	2%	3%	4%	4%	4%	3%	3%	2%
7	1%	1%	1%	1%	1%	1%	0%	-1%	-4%	-8%	-10%	-9%	-6%	-4%	-1%	0%	4%	5%	6%	5%	5%	[illegible]	2%	2%
8	1%	1%	1%	1%	1%	1%	1%	-1%	-3%	-7%	-10%	-9%	-7%	-4%	-2%	-0%	4%	5%	6%	6%	5%	3%	2%	1%
9	1%	1%	1%	1%	1%	1%	1%	-0%	-2%	-6%	-9%	-9%	-7%	-5%	-2%	-0%	3%	5%	5%	5%	5%	3%	2%	1%
10	0%	1%	1%	1%	1%	1%	1%	0%	-2%	-6%	-8%	-9%	-7%	-4%	-2%	-0%	3%	5%	5%	5%	4%	2%	2%	1%
11	0%	0%	0%	0%	0%	0%	0%	-1%	-3%	-6%	-7%	-7%	-5%	-3%	-1%	1%	4%	5%	5%	4%	3%	2%	1%	1%
12	-0%	-0%	0%	0%	0%	0%	0%	-0%	-2%	-4%	-6%	-6%	-5%	-3%	-1%	1%	4%	5%	4%	3%	2%	1%	1%	1%

Utility Avoided Cost Hourly Optimized Discharge (+) Charge (-) kWh / kWh Capacity

month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	-0%	-0%	0%	-0%	-0%	2%	7%	10%	2%	-1%	-5%	-8%	-10%	-11%	-9%	-2%	0%	4%	6%	1%	4%	4%	2%	-0%
2	-0%	0%	-0%	-0%	-0%	2%	18%	2%	-0%	-2%	-6%	-8%	-12%	-10%	-9%	-5%	-1%	6%	2%	2%	7%	6%	4%	-0%
3	-0%	-0%	-0%	-0%	-0%	4%	14%	4%	3%	2%	-4%	-5%	-9%	-11%	-12%	-8%	-5%	1%	3%	7%	9%	8%	3%	-0%
4	-0%	-0%	-0%	-0%	-0%	2%	14%	4%	1%	-1%	-5%	-9%	-12%	-12%	-10%	-8%	-9%	-0%	3%	13%	8%	13%	5%	1%
5	-0%	-0%	-0%	-0%	-0%	4%	8%	-0%	-2%	-4%	-10%	-8%	-7%	-7%	-9%	-10%	-7%	-3%	1%	17%	19%	10%	1%	-0%
6	-0%	-0%	-0%	-0%	-0%	5%	0%	-1%	-3%	-6%	-7%	-5%	-8%	-8%	-10%	-7%	-7%	-1%	-1%	19%	21%	7%	4%	2%
7	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-2%	-7%	-13%	-16%	-12%	-9%	0%	2%	-6%	-4%	-1%	[illegible]	24%	20%	3%	2%	0%
8	-0%	-0%	-0%	-0%	-0%	0%	1%	0%	-5%	-9%	-14%	-16%	-9%	-2%	-3%	0%	-1%	-2%	9%	23%	8%	6%	6%	-0%
9	-0%	-0%	-0%	-0%	-0%	-0%	10%	5%	-3%	-6%	-9%	-13%	-9%	-9%	-5%	1%	-6%	5%	21%	3%	2%	3%	1%	0%
10	1%	-0%	-0%	-0%	-0%	0%	8%	14%	-0%	-6%	-9%	-12%	-8%	-9%	-11%	-6%	-1%	5%	13%	5%	6%	4%	2%	0%
11	-0%	-0%	-0%	-0%	-0%	3%	16%	7%	-2%	-7%	-7%	-7%	-12%	-11%	-8%	-1%	8%	7%	4%	1%	5%	6%	2%	-0%
12	-0%	-0%	-0%	-0%	-0%	0%	8%	6%	1%	-4%	-5%	-8%	-8%	-8%	-5%	-0%	4%	5%	1%	0%	3%	4%	6%	1%

GHG Hourly Optimized Discharge (+) Charge (-) kWh / kWh Capacity

month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	1%	1%	1%	-0%	-0%	3%	[illegible]	7%	2%	-0%	-5%	-8%	-10%	-11%	-9%	-3%	1%	2%	4%	3%	5%	2%	3%	0%
2	1%	-0%	-0%	-0%	-0%	2%	[illegible]	1%	-0%	-3%	-6%	-8%	-12%	-11%	-9%	-5%	-1%	5%	6%	1%	8%	9%	4%	-0%
3	-0%	-0%	-0%	-0%	0%	3%	14%	5%	3%	1%	-3%	-6%	-10%	-11%	-11%	-8%	-5%	0%	3%	8%	8%	5%	3%	-0%
4	1%	-0%	-0%	-0%	0%	3%	12%	2%	1%	-1%	-7%	-9%	-11%	-13%	-9%	-7%	-9%	-1%	2%	14%	9%	14%	4%	-0%
5	1%	1%	-0%	-0%	-0%	6%	6%	-0%	-2%	-4%	-9%	-9%	-6%	-10%	-8%	-9%	-6%	-2%	1%	18%	19%	9%	1%	-0%
6	-0%	-0%	-0%	-0%	0%	6%	0%	-1%	-2%	-5%	-7%	-6%	-8%	-8%	-10%	-7%	-8%	-2%	-1%	18%	22%	6%	3%	2%
7	1%	-0%	-0%	-0%	-0%	-0%	1%	-2%	-7%	-13%	-15%	-11%	-7%	4%	7%	-3%	-6%	-2%	-1%	26%	15%	3%	1%	3%
8	0%	1%	-0%	-0%	-0%	2%	7%	1%	-5%	-9%	-14%	-15%	-9%	0%	-1%	3%	-0%	-2%	2%	17%	3%	5%	6%	0%
9	-0%	-0%	-0%	-0%	-0%	1%	13%	4%	-3%	-5%	-9%	-13%	-9%	-8%	-5%	1%	-5%	6%	17%	0%	2%	5%	2%	0%
10	0%	0%	0%	-0%	0%	1%	7%	10%	-1%	-6%	-9%	-12%	-8%	-10%	-10%	-6%	-1%	6%	15%	2%	6%	7%	1%	0%
11	-0%	-0%	-0%	-0%	-0%	3%	16%	5%	-2%	-6%	-7%	-8%	-11%	-11%	-7%	-2%	9%	7%	4%	3%	6%	4%	2%	-0%
12	-0%	-0%	-0%	-0%	-0%	0%	8%	4%	1%	-4%	-5%	-9%	-8%	-7%	-5%	-1%	4%	6%	1%	0%	4%	5%	7%	1%

Bill Impact Hourly Optimized Discharge (+) Charge (-) kWh / kWh Capacity

month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-1%	-4%	-6%	-8%	-7%	-6%	-5%	-1%	4%	9%	4%	13%	5%	0%	0%	-0%
2	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-2%	-5%	-7%	-9%	-8%	-7%	-7%	-1%	5%	11%	5%	14%	7%	0%	0%	-0%
3	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-1%	-4%	-8%	-8%	-8%	-8%	-7%	-1%	6%	9%	4%	13%	6%	0%	0%	0%
4	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-2%	-5%	-7%	-10%	-9%	-8%	-8%	-1%	5%	15%	5%	14%	6%	0%	0%	0%
5	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-1%	-2%	-5%	-7%	-8%	-8%	-8%	-9%	-2%	6%	13%	5%	12%	7%	-0%	0%	0%
6	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-1%	-3%	-6%	-8%	-10%	-11%	-10%	-12%	-4%	[illegible]	15%	[illegible]	16%	12%	-0%	-0%	-0%
7	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-1%	-2%	-6%	-9%	-11%	-11%	-10%	-12%	-4%	8%	16%	9%	16%	12%	-0%	-0%	-0%
8	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-2%	-6%	-9%	-12%	-11%	-10%	-11%	-4%	7%	17%	[illegible]	17%	10%	-0%	-0%	-0%
9	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-2%	-5%	-8%	-11%	-12%	-11%	-12%	-4%	10%	15%	[illegible]	17%	[illegible]	-0%	-0%	-0%
10	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-1%	-4%	-7%	-9%	-8%	-8%	-8%	-1%	8%	11%	6%	12%	6%	0%	0%	-0%
11	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-1%	-2%	-5%	-8%	-9%	-8%	-6%	-5%	-1%	7%	9%	6%	12%	7%	0%	0%	-0%
12	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-0%	-2%	-4%	-8%	-8%	-7%	-6%	-4%	-0%	5%	8%	5%	10%	5%	0%	0%	-0%

The following two figures (Figure 5-5 and Figure 5-6) display the average weekday battery dispatch pattern for the three optimization scenarios (solid dark lines), alongside the actual dispatch pattern during the same period (dashed dark lines). The shaded yellow areas represent times where more charging occurs than actual, and the green shaded area signifies more discharge than actual from optimal dispatch. The vertical lines highlight the typical peak pricing period of 4pm – 9pm. Figure 5-5 presents the average dispatch in August and Figure 5-6 presents the average dispatch in March. In all cases, the optimal scenarios charge and discharge more completely than the actual dispatch activity. The optimal GHG and optimal avoided cost scenarios discharge more significantly in August compared to March. This is due to higher marginal GHG emissions and higher utility costs in August.

The optimal customer bill discharge pattern is relatively consistent between August and March. The optimal customer bill discharge pattern typically discharges more energy during the 8pm hour, followed by 4pm – 6pm. This dual-peak discharge pattern is due to the mixed-integer linear program choosing one of many possible optimal discharge patterns. The model chooses to maximally discharge at the end of the peak price period (typically 8pm – 9pm), followed by additional discharge during earlier hours (favoring hours with more rapidly increasing net load). Customer bills could be similarly optimally reduced by a more even discharge across the peak price period (typically 4pm – 9pm or 5pm – 8pm). In a real-world scenario, there may be other considerations beyond cost that would favor a more even discharge across the peak price period, such as unexpected changes in forecasted load which could reduce the economic benefit in certain hours of the peak price period.

FIGURE 5-5: AVERAGE ACTUAL AND OPTIMAL DISPATCH ON WEEKDAYS IN AUGUST 2023

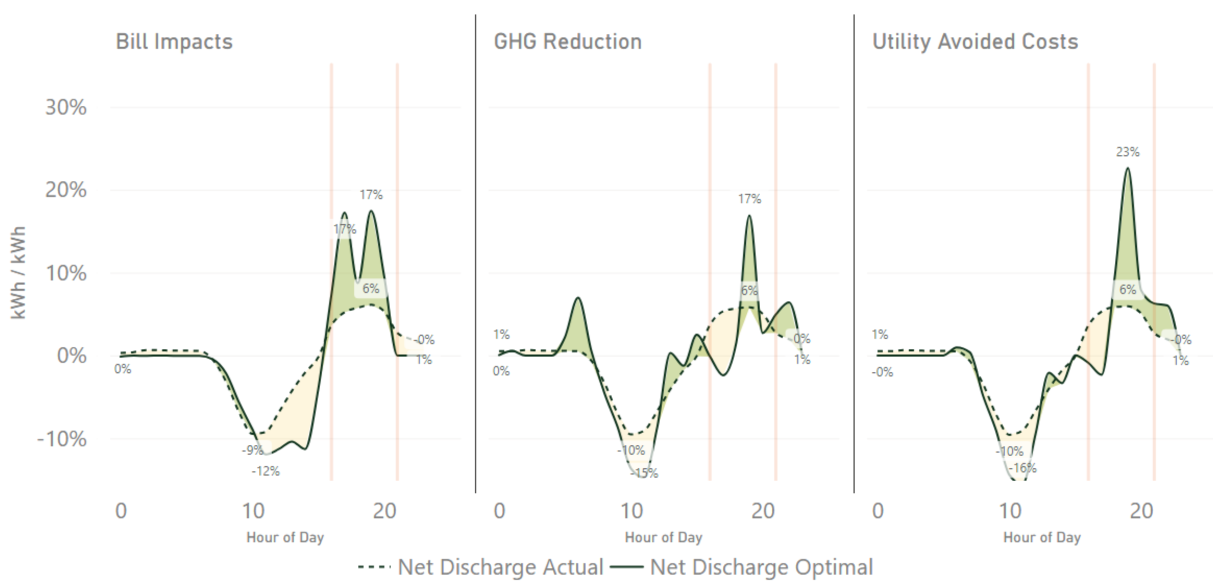


FIGURE 5-6: AVERAGE ACTUAL AND OPTIMAL DISPATCH ON WEEKDAYS IN MARCH 2023

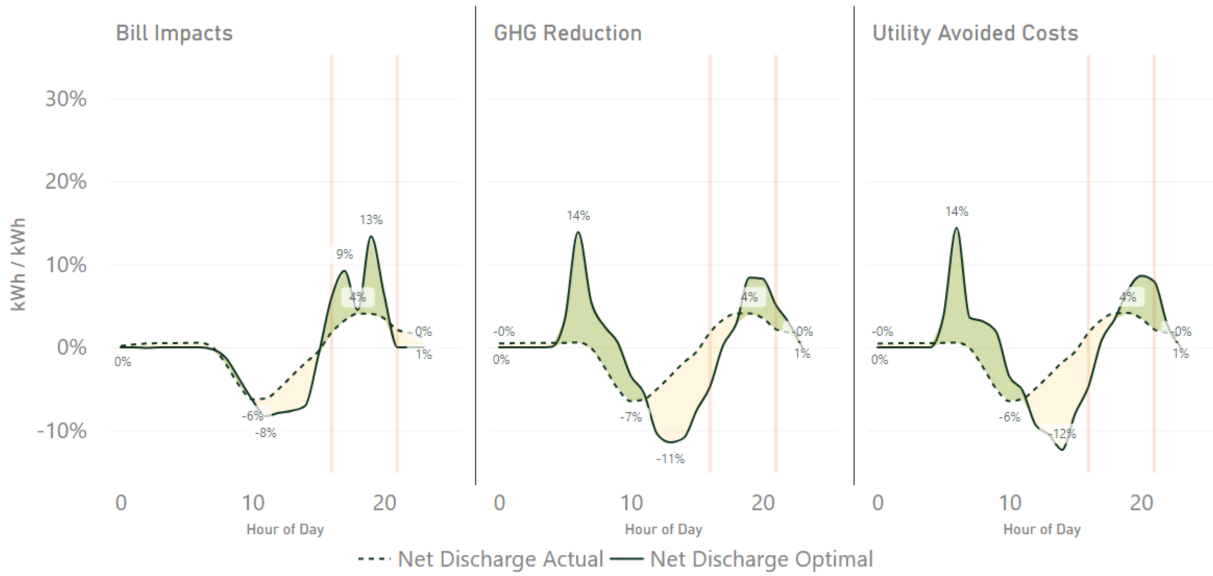


Figure 5-7 through Figure 5-9 provide the actual and optimal daily dispatch during weekdays by month of the year. Here, much like with the heatmaps presented above, we observe how optimal dispatch differs based on the time of day and time of year as storage dispatch responds to differing GHG and avoided cost signals throughout the year. The timing of dispatch in the bill savings scenario remains unchanged during the year, but the greater magnitude of discharge in summer months follows higher on-peak retail rates on customer bills.

FIGURE 5-7: AVERAGE ACTUAL AND AVOIDED COST OPTIMAL DISPATCH BY MONTH AND HOUR

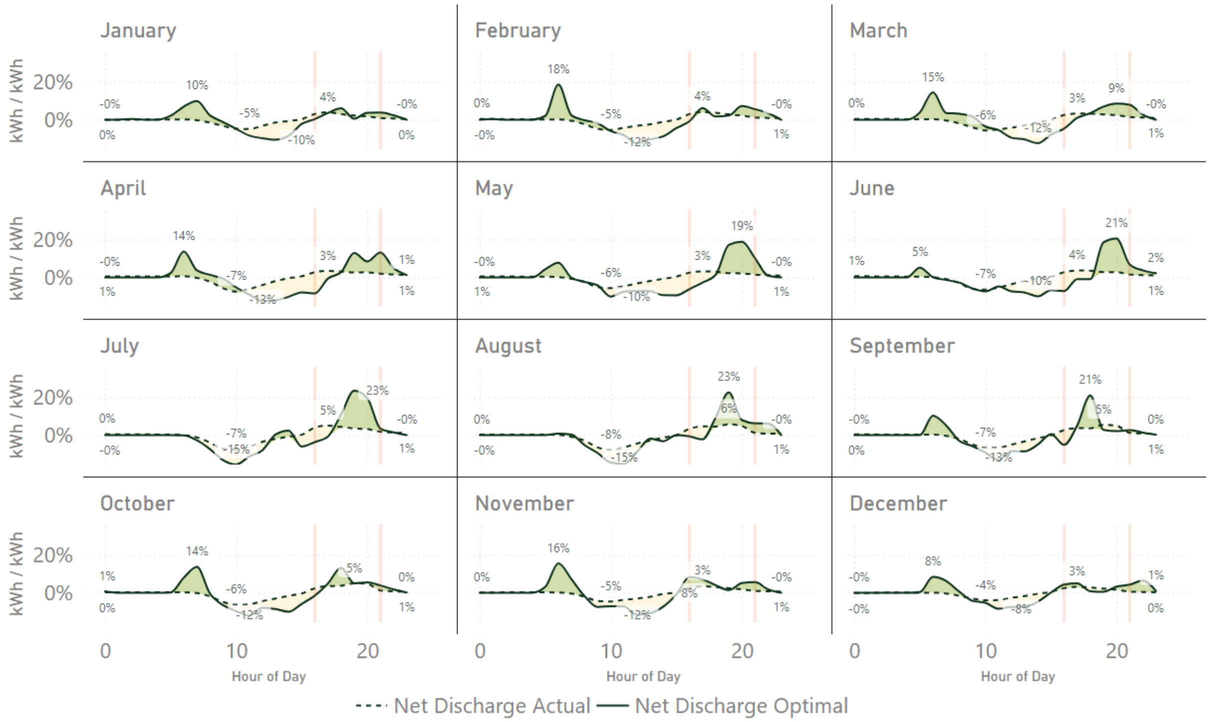


FIGURE 5-8: AVERAGE ACTUAL AND GHG OPTIMAL DISPATCH BY MONTH AND HOUR

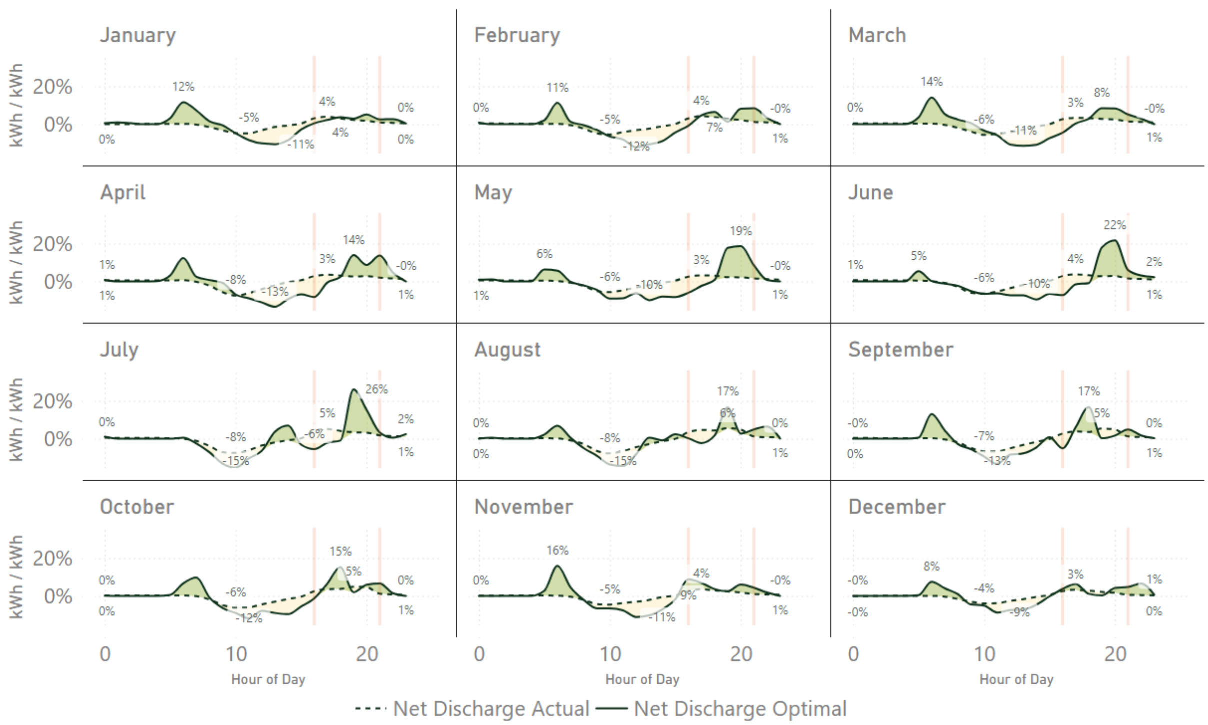
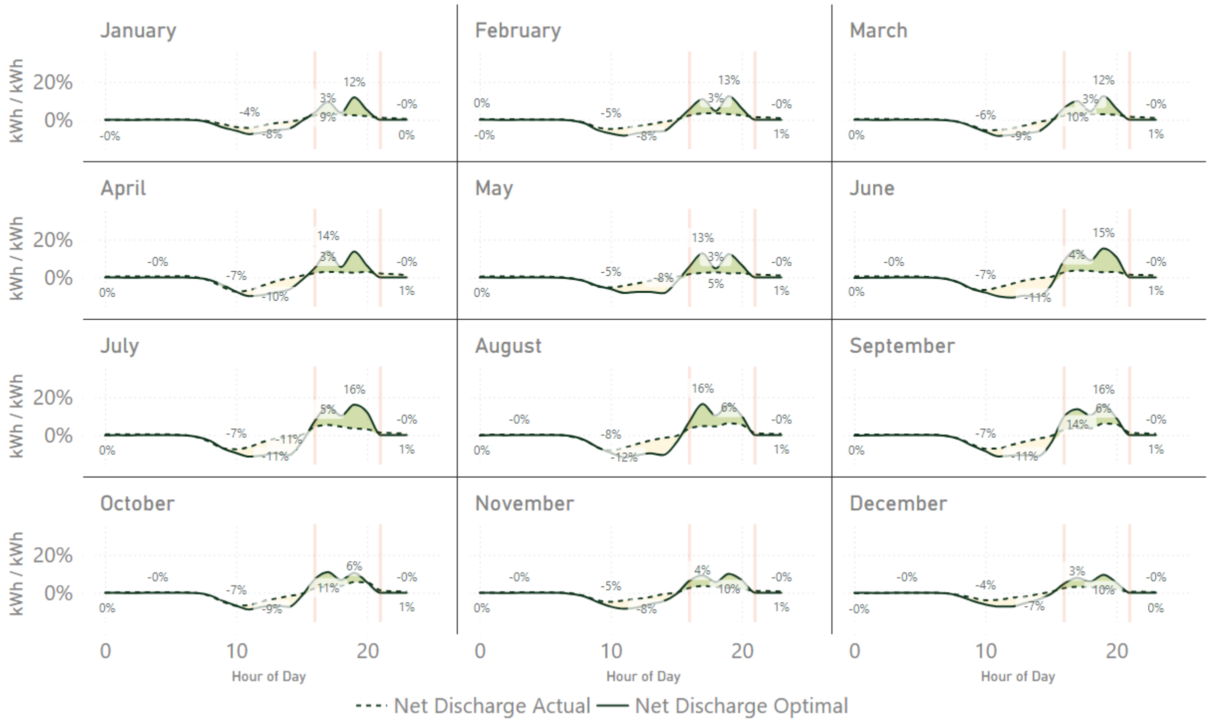


FIGURE 5-9: AVERAGE ACTUAL AND BILL IMPACTS OPTIMAL DISPATCH BY MONTH AND HOUR



APPENDIX A BILL SAVINGS ANALYSIS

We estimated bill savings for the 2023 SGIP energy storage evaluation through use of Verdant's distributed energy resource cost effectiveness analysis tool (DER CAT). Monthly and annual bills were estimated using the tool's bill calculation module. To estimate bill savings, we calculated a customer's bill using their historical hourly net load and an estimated baseline load. The baseline load was defined as the net load minus the hourly storage dispatch activity. Bill savings were calculated as the difference between the actual and baseline bills. Table A-1 and Table A-2 present the actual rate schedules used to develop 2023 bill impacts for residential and nonresidential SGIP participants, respectively. These are further disaggregated by IOU.

TABLE A-1: DISTRIBUTION OF RESIDENTIAL RATE SCHEDULES IN ANALYSIS BY IOU

IOU	Rate Schedule	2023	
		Sample Count	Percent (%)
PG&E	AG-A1	1	<1%
	E-1	5	1%
	E-ELEC	1	<1%
	E-TOU-B	28	3%
	E-TOU-C	266	28%
	E-TOU-D	23	2%
	EM-TOU	1	<1%
	EV-A	28	3%
	EV2-A	605	63%
	Subtotal	**958**	**100%**
SCE	D	13	3%
	D-CARE	1	<1%
	TOU-D-A	56	12%
	TOU-D-A-CARE	2	<1%
	TOU-D-B	4	1%
	TOU-D-PRIME	234	52%
	TOU-D-PRIME-CARE	9	2%
	TOU-D-PRIME-FERA	1	<1%
	TOU-D-T	1	<1%
	TOU-D_4_9	59	13%
	TOU-D_4_9-CARE	2	<1%
	TOU-D_4_9-FERA	1	<1%

	TOU-D_5_8	63	14%
	TOU-D_5_8-CARE	2	<1%
	TOU-GS1-E	1	<1%
	Subtotal	**449**	**100%**
SDG&E	DR	11	4%
	DRSES	73	28%
	EV-TOU-2	13	5%
	EV-TOU-5	34	13%
	TOU-DR	8	3%
	TOU-DR1	112	43%
	TOU-DR2	10	4%
	Subtotal	**261**	**100%**
All	**Total**	**1,668**	

TABLE A-2: DISTRIBUTION OF NONRESIDENTIAL RATE SCHEDULES IN ANALYSIS BY IOU

IOU	Rate Schedule	2023	
		Sample Count	Percent (%)
PG&E	A-6	3	1%
	A10-X	3	1%
	AG-5-B	1	<1%
	AG-A1	2	1%
	AG-C	3	1%
	B-1	5	2%
	B-10	18	7%
	B-19	136	51%
	B-19_1v	2	1%
	B-20_1v	14	5%
	B-20_2v	5	2%
	B-20_t	1	<1%
	B-19 Option S	22	8%
	B-20_2v Option S	1	<1%
	B-20_t Option S	2	1%
	B-6	4	2%
	E-19	27	10%
	E-19_1v	7	3%

	E-20_1v	9	3%
	E-20_2v	1	<1%
	Subtotal	**266**	**100%**
SCE	TOU-8-B	3	1%
	TOU-8-D	64	19%
	TOU-8-E	12	4%
	TOU-8-R	10	3%
	TOU-D-PRIME	1	<1%
	TOU-EV-9-2kv	15	4%
	TOU-EV-NR-8	10	3%
	TOU-GS1-B	1	<1%
	TOU-GS1-D	1	<1%
	TOU-GS2-B	1	<1%
	TOU-GS2-D	39	11%
	TOU-GS2-E	20	6%
	TOU-GS2-R	42	12%
	TOU-GS3-B	8	2%
	TOU-GS3-D	48	14%
	TOU-GS3-E	14	4%
	TOU-GS3-R	18	5%
	TOU-PA2-D	4	1%
	TOU-PA2-E	9	3%
	TOU-PA3-A	2	1%
	TOU-PA3-B	2	1%
	TOU-PA3-D	9	3%
	TOU-PA3-E	9	3%
	Subtotal	**342**	**100%**
SDG&E	A6-TOU_1v	1	1%
	AL-TOU_<500kW_1v	69	54%
	AL-TOU_>500kW_1v	8	6%
	AL-TOU2_<500kW_1v	9	7%
	AL-TOU2>500kW_1v	6	5%
	DG-R_<500kW_1v	24	19%
	DG-R_>500kW_1v	5	4%
	DG-R_>500kW_2v	1	1%

VERDANT

	PAT-1_1v	2	2%
	PAT-1_2v	1	1%
	TOU-M	2	2%
	Subtotal	**128**	**100%**
All	**Total**	**736**	

Updating the Model

The DER CAT contains detailed IOU tariff information that is used to calculate customer bills. For this analysis, we entered rate information for tariffs as of June 2023. The tool captures full information about TOU periods, tiered rates, and demand charges. Figure A-1 shows an example of hour the TOU periods are captured inside the model.

FIGURE A-1: DER CAT HOURLY TIME-OF-USE INPUT SHEET

RateName	Season	WeekEndHoliday	H00	H01	H02	H03	H04	H05	H06	H07	H08	H09	H10	H11	H12	H13	H14	H15	H16	H17	H18	H19	H20	H21	H22	H23
TOU-DR1	Summer	Weekday	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	On	On	On	On	On	Off	Off	Off
TOU-DR1	Summer	Weekend	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	Off	Off	On	On	On	On	On	Off	Off	Off
TOU-DR1	Winter	Weekday	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	On	On	On	On	On	Off	Off	Off
TOU-DR1	Winter	Weekend	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	Off	Off	On	On	On	On	On	Off	Off	Off
TOU-DR1	MarchApril	Weekday	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	Off	Off	Off	Off	SuperOff	SuperOff	SuperOff	SuperOff	Off	Off	On	On	On	On	On	Off	Off	Off
TOU-DR1	MarchApril	Weekend	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	Off	Off	On	On	On	On	On	Off	Off	Off
TOU-DR1	Summer	Holiday	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	Off	Off	On	On	On	On	On	Off	Off	Off
TOU-DR1	Winter	Holiday	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	Off	Off	On	On	On	On	On	Off	Off	Off
TOU-DR1	MarchApril	Holiday	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	SuperOff	Off	Off	On	On	On	On	On	Off	Off	Off

All sub-components of an individual tariff are captured for energy and demand charges. Figure A-2 shows an example of the rate components that are recorded in the tool. The rate's subcomponents are tracked separately so that non-bypassable charges are handled appropriately in bill calculations. Demand charges are also recorded in the tool, separating out peak, non-coincident, and TOU charges for transmission and distribution.

FIGURE A-2: DER CAT RATE INPUT SHEET

Season	TOU	Tier	Transm	Distr	PPP	ND	CTC	LGC	RS	TRAC	CostRe	PUCRF	BaselineDis	UDC	DWRBond	EECCDWR	TotalNBP	TotalRate
Summer	On	NA	0.07248	0.13991	0.01851	0.00007	0.0011	0.0039	0.00001	0.01476				0.25074	0.00652	0.43976	0.0262	0.69702
Summer	Off	NA	0.07248	0.13991	0.01851	0.00007	0.0011	0.0039	0.00001	0.01476				0.25074	0.00652	0.19788	0.0262	0.45514
Summer	SuperOff	NA	0.07248	0.13991	0.01851	0.00007	0.0011	0.0039	0.00001	0.01476				0.25074	0.00652	0.07083	0.0262	0.32809
Winter	On	NA	0.07248	0.13991	0.01851	0.00007	0.0011	0.0039	0.00001	0.1541				0.39008	0.00652	0.14857	0.0262	0.54517
Winter	Off	NA	0.07248	0.13991	0.01851	0.00007	0.0011	0.0039	0.00001	0.1541				0.39008	0.00652	0.08335	0.0262	0.47995
Winter	SuperOff	NA	0.07248	0.13991	0.01851	0.00007	0.0011	0.0039	0.00001	0.1541				0.39008	0.00652	0.06442	0.0262	0.46102
Summer	_ALL_												-0.10159	-0.10159			0	-0.10159
Winter	_ALL_												-0.10159	-0.10159			0	-0.10159

Bill Calculation

Each annual bill is calculated by first summarizing the monthly kW and kWh by tier and/or TOU period. These monthly totals are then multiplied by the applicable $/kW or $/kWh provided in the given utility rate sheet. This process allows many different rate structures to be utilized in the same calculator. The annual bill is then calculated by summing each of the monthly kW and kWh components. The bill calculations assume that the monthly billing cycles align with calendar months. Exports were reimbursed at the full retail rate (NEM 2.0). The billing analysis for this project involves estimating bills for each customer under two scenarios: actual customer usage with a battery, and customer usage if their system was not paired with battery storage. The bill calculation tool is run over the usage from both scenarios, creating annual bills for both scenarios. The difference between these bills is the bill savings we report.

APPENDIX B DATA SOURCES AND QUALITY CONTROL

This appendix provides an overview of the primary sources of data used to quantify the energy and peak demand impacts of the 2023 Self-Generation Incentive Program (SGIP) and the data quality and validation process.

B.1 DATA SOURCES

The primary sources of data include:

- The statewide project list managed by the Program Administrators (PAs),
- Site inspection and verification reports completed by the PAs or their consultants,
- Metered storage and generation data provided by project developers, the SGIP Data Portal, directly from customers, or from performance data providers,
- Metered load and PV generation data from project developers, and
- Interval load data provided by the electric utilities.

B.1.1 Statewide Project List and Site Inspection Verification Reports

The statewide project list contains information on all projects that have applied to the SGIP. Critical fields from the statewide project list include:

- Project tracking information such as the reservation number, facility address, program year, payment status/date, and eligible/ineligible cost information, and
- Project characteristics include technology/fuel type, rebated capacity, fuel types, and equipment manufacturer/model.

Data obtained from the statewide project list are verified and supplemented by information from site inspection verification reports. The PAs or their consultants perform site inspections to verify that installed SGIP projects match the application data and to ensure they meet minimum requirements for program eligibility. Our team reviews the inspection verification reports to verify and supplement the information in the statewide project list. Additional information in verification reports include descriptions of storage and generation capacity, differences between incentivized and nameplate capacities, and identification of existing metering equipment that can be used for impact evaluation purposes, fuel descriptions and percentage of biogas, and details surrounding heat recovery.

B.1.2 Interval Load Data and Metered Data

Metered energy storage charge and discharge data are requested and collected from system manufacturers and developers for performance-based incentive (PBI) and non-PBI projects, and from Energy Solutions for projects that received a PBI incentive. Metered energy generation, fuel consumption, and heat recovery data were requested directly from customers and performance data providers, as well as downloaded from the Energy Solutions data portal for those projects still within their PBI period. Interval load data for each project were requested from Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) for 2023. These data were requested to allow analysis of noncoincident peak (NCP) demand impacts and to better analyze energy storage dispatch. Due to the confidential nature of customer load data, we signed nondisclosure agreements (NDAs) with each of the utilities to obtain the load data. Once load data were received and processed, we matched them to available charge/discharge data to allow project-by-project analysis of the customer demand impacts of SGIP. Table B-1 provides a summary of the types of data requested and used in the analysis as well as the data source(s).

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TABLE B-1: DATA REQUESTED AND DATA SOURCES

Types of Data Requested/Used/Received	SGIP Project Database	Energy Solutions	Project Developer	Customers	PDPs	IOU
SGIP reservation number	X	X	X			
Capacity (kW, duration, kWh for Storage), kW for generation	X		X			
Program year (PY) of application and upfront payment date	X					
Customer sector	X					
Payment type (PBI vs. Non-PBI)	X	X				
Incentive	X					
Project developer	X		X			
Battery manufacturer	X		X			
Interval Charge and discharge data (kWh)		X	X			
Interval electrical generation, fuel consumption, and heat recovery		X	X	X	X	
15-minute customer load data (kWh)			X			X
Renewable on-site generation (kWh)			X			X
Treatment of daylight savings		X	X	X	X	X
Data period beginning or ending		X	X	X	X	X
Unit of measure (kW, kWh, W, Wh, etc)		X	X	X	X	X
Status of storage system (operational/off-line)			X			
Storage system use case – TOU bill arbitrage, coincident/non-coincident demand charge reduction, PV self-consumption, backup, demand response/wholesale market participation			X			
How system interacts with on-site renewable			X			
Customer utility tariff			X			X
Flow Direction (delivered vs. received) for bi-directional meters						X
Dates and times of any DR, capacity or other program participation			X			X
Dates and times of planned/unplanned outages (PSPS, etc)			X			X
SubLAP associated with the geographic location of customer						X

B.2 DATA CLEANING

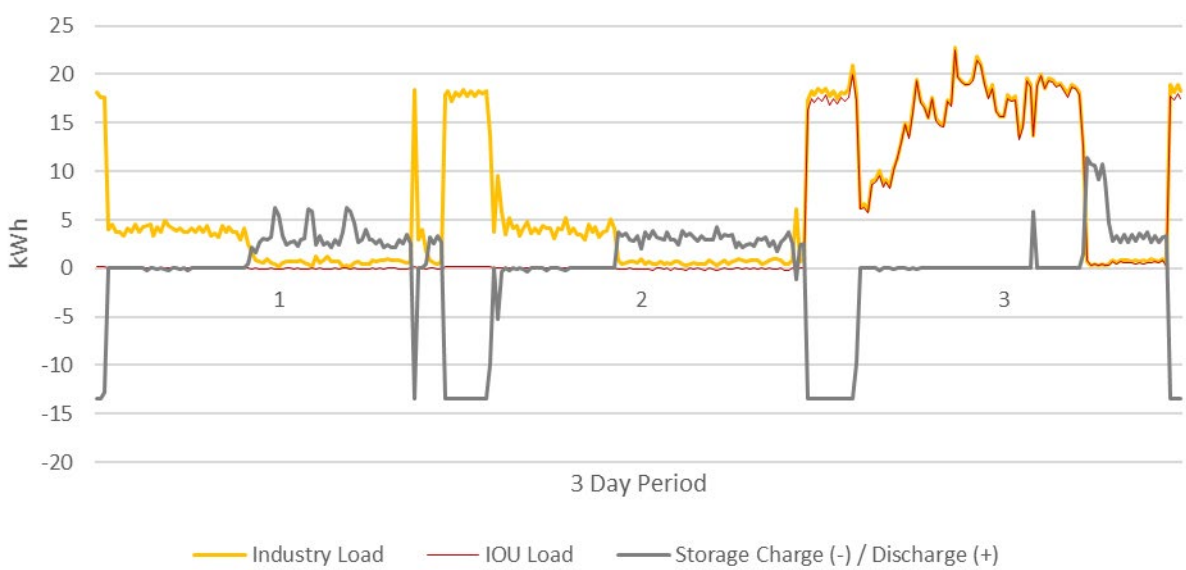
As discussed above, the analysis leveraged a variety of data sources from project developers, Energy Solutions (for projects that received a PBI incentive), directly from customers and performance data providers, and the electric utilities. We conducted an extensive data cleaning and quality control exercise to ascertain whether the data were verifiable:

- Interval battery, electrical generation, fuel consumption, heat recovery, and load data were aligned to Pacific Standard Time (PST). Data for each time interval were set to the beginning of the time interval.
- Visual inspections of storage dispatch, generator, and load data were conducted for all projects where we received data. This allowed the evaluation team to verify if, for example, metered load data increased at the same time interval as the battery was charging (time syncing), or if both fuel consumption and electrical generation showed consistencies. This step also identified sites with differing or inconsistent timestamps, and load data with the wrong sign (i.e. negative when it should be positive and positive when it should be negative).
- When battery data were provided by the project developer and the PBI database, we conducted quality control (QC) on both data streams and, often, stitched the data throughout the year to develop a more robust data set for each project.
- When load data were provided by the project developer and the IOU, we conducted QC on both data streams and, often, stitched the data throughout the year to develop a more robust data set for each project.
- We reviewed hourly, daily and monthly performance metrics to determine whether the data were accurate.
- We reviewed battery capacities and generation capacities in the program tracking database to verify they were accurate.
- We reviewed the battery storage data usage to identify the start date of valid data.
- We identified outliers in battery data by setting any 15-minute charge and discharge power that is above the rated capacity of the battery times four as abnormal spikes. Outliers were also identified in electrical output and fuel generation data.
- We identified battery storage data that signified possible data quality issues:
  - Round trip efficiency over 92.5 percent
  - Maximum battery discharge as a percentage of kW capacity greater than 2
  - The 99th percentile of battery storage discharge as a percentage of kWh capacity greater than 1, indicating the possibility of a second battery installed that was not installed through SGIP

Figure B-1 conveys a visualization of the data cleaning process. This is a three-day example that was mocked up to represent one of the storage projects. The yellow line represents the load data that would have been provided by the project developer. The red line represents the IOU load, and the gray line represents the storage dispatch behavior. This example illustrates a couple of data cleaning exercises we performed:

- We can confirm the sync between the battery and load data. When the battery is charging (-) the load increases on the same time stamp.
- The IOU load data in this representative example is missing throughout the first day and halfway through the second day. The IOU data does not match with the project developer data until midnight on the third day (see between 2 and 3 below). We could stitch the two load streams and not lose the first two days.

FIGURE B-1: EXAMPLE 1 OF DATA CLEANING AND QC PROCESS FOR A HYPOTHETICAL STORAGE PROJECT



We received battery storage data that sometimes started before the interconnected date, but still appeared to be valid, usable data. To retain the most amount of valid data, we reviewed the data received to determine an analysis start date. For most of the sites, this was not an issue, as they we interconnected prior to 2021. However, for the ones that were interconnected in 2023, we determined the start date as follows:

- If the upfront payment date came before the date that the battery first cycled then the start date used was the most recent of either the upfront payment date or the first date of any data,
- Else if there was no battery cycling in the winter then the start date used was the first date of any data,

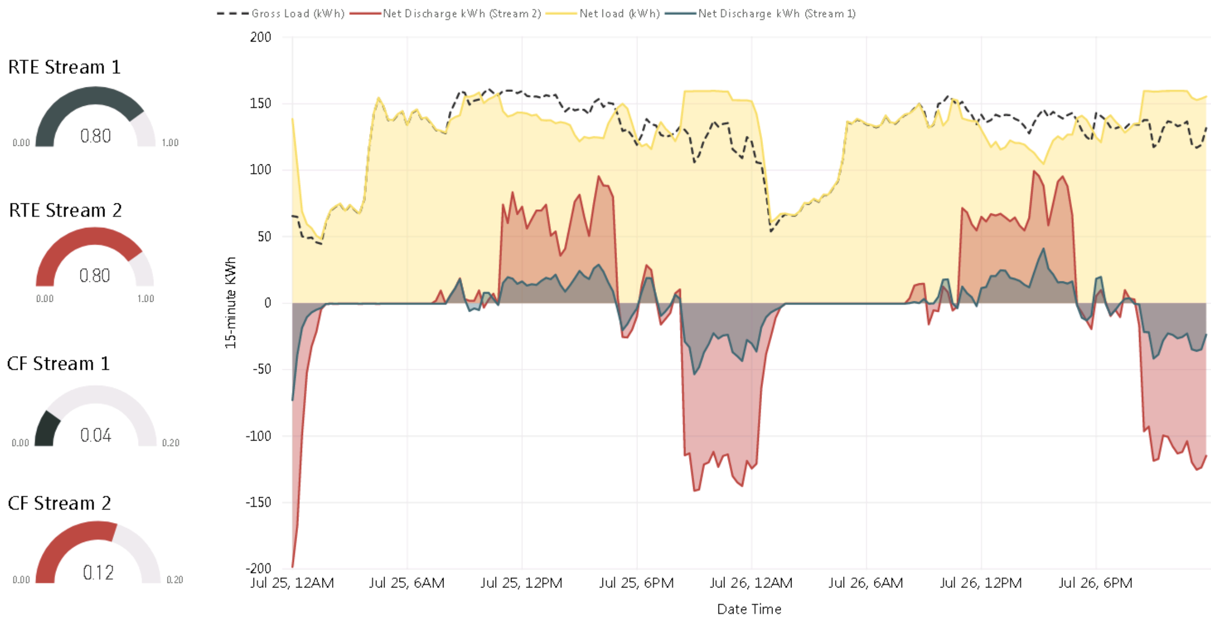
- Else the start date used was the first date the battery started cycling.

Storage systems inherently increase energy consumption. Because of losses in the battery, less energy can be discharged than is stored in the battery. This fact provided an additional QC benefit. After we removed data that was completely missing or clearly corrupt, we examined the roundtrip efficiency (RTE) – which is the ratio of total discharge to total charge energy – for each project by hour, day, and month. Since energy discharged cannot be greater than energy stored, we identified potential data issues by reviewing projects that exhibited RTEs greater than one at the monthly level (Section 6 discusses this performance metric in detail).

For the residential projects, looking for the appearance of a second battery addition was an additional QC step that was implemented in this evaluation. When the 99th percentile of battery storage discharge as a percentage of kWh capacity was greater than 1, we quarantined the sites for review. The time series data was manually reviewed to assess the date of when the additional battery appears, and the storage data was pro-rated after that point so that the savings will only reflect that of the battery installed through the program.

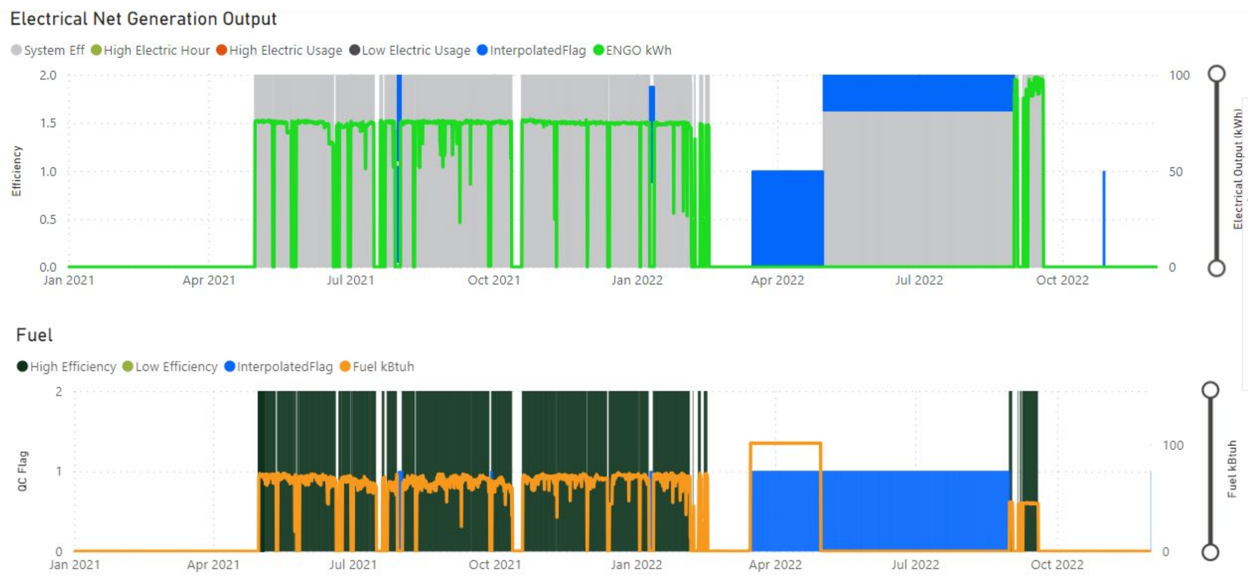
Another QC check was also conducted where the evaluation team received multiple streams of data. Capacity factors and RTEs have expected ranges, therefore observations that fall outside of these ranges are flagged for further review. Figure B-2 illustrates this initial data cleaning step – where we compare the RTE and CF from two distinct data streams. While the RTE for both streams are identical (and within an expected range) the CFs for both streams are different. These data are flagged for further analysis. This analysis would reveal that “Stream 1” is the appropriate storage net discharge profile for this project. The magnitude of net discharge for “Stream 2” is too great, given the metered load profile for this facility.

FIGURE B-2: EXAMPLE 2 OF DATA CLEANING AND QC PROCESS FOR A HYPOTHETICAL STORAGE PROJECT



On the generation side, dashboards were developed which included hourly electrical, fuel, and heat data, as well as a calculation of efficiency, and flags indicating whether the electric output appeared too high. An example is shown below in Figure B-3. For this project, the calculated efficiency of the system was between 200-300%, indicating that the fuel data may not be complete, or the electrical output may include output for another generator. In this case, the electrical output seemed reasonable, within the reasonable range based on the size of the generator, but the fuel data could not be validated, so we dropped the fuel data from the analysis, but kept the electrical generation data.

FIGURE B-3: EXAMPLE 3 OF DATA CLEANING AND QC PROCESS FOR A GENERATION PROJECT



One final QC check was implemented to ensure the quality of data was within expected ranges for billing calculation. All of the solar generation data was stratified by meter and hour and normalized by assigning a z-score to each datapoint. Any data points with a z-score greater than 7.5 or less than –7.5 were removed from the final dataset. This retains more than 99.999% of the data, while removing the occasional extremely anomalous value. This process was followed up with manual verification to ensure that the data points being removed were in fact anomalous.

To accurately estimate billing impacts, there can be no missing values in the netload dataset for a given household. If data was missing, or removed in the step previous anomaly detection step, it was replaced with interpolated data from the same meter. In the case of data gaps spanning less than two hours, data was interpolated linearly between the nearest known datapoints. For gaps larger than two hours, the interpolation was done by recreating a hypothetical load based on a matching month, hour, and meter. This may fill in the gap with data from earlier or later in the month and averaged together with the data from the previous year’s load shape as well. To ensure quality interpolation of data, gaps must meet certain requirements: The total amount of data missing must be less than 30% of all data available, and no single gap can be larger than two weeks, or 336 consecutive hours.

APPENDIX C SAMPLING PLANS AND DATA COLLECTION OUTCOMES

This section details the sampling approach used for the 2023 SGIP impact evaluation. The sampling strategy was designed to provide statistically significant impacts while maintaining evaluation delivery timelines and project budgets. The sample design was informed by many of the program attributes discussed above in previous sections, and how they have changed and evolved over time. Sampling plans for energy storage and generation are described below. Different approaches were used for these two program elements due to material differences in their population sizes.

FIGURE C-1: SAMPLE DESIGN CONSIDERATIONS

Program Understanding	Design Considerations
Composition of the SGIP storage and generation projects	
Data for key segmentation variables will be obtained from the program tracking database and summarized in the research planning phase.	• Customer sector, PBI designation, budget category, program year • Project developer, technology type and manufacturer • Permanency or legacy status • System capacity, presence of on-site generation • PSPS outage and high fire threat district (HFTD) designation
Availability of underlying data requirements and historical data limitations	
Our extensive experience evaluating the SGIP, and our knowledge of the program, provide us with a unique understanding of what data is realistically available to collect for M&E purposes.	• Decommissioned generation and storage projects • Residential storage systems with ineffective data collection systems • Operational status research (OSR)
Reporting requirements stemming from passage of D.19-08-001	
This decision developed GHG emissions requirements and compliance pathways for developer "fleets". It directs the impact evaluator to provide summarized GHG performance of developer fleets as part of the annual SGIP impact evaluations.	• Different compliance pathways for "new" vs. "legacy" projects • Defines project developer fleets • Differs by legacy status, customer sector, permanency period • Increased sample sizes required
Previous evaluation experience and lessons learned	
Our team understands the drivers of uncertainty surrounding key reporting metrics from past impact evaluation work.	• Development of coefficients of variation based on design variables • Optimal sample design which achieves desired levels of precision without excessive data collection

C.1 ENERGY STORAGE

For the energy storage population, the sample design was based on several factors: 1) the composition of the 2023 population of SGIP storage projects, including budget category, payment year, service territory installation, project developer, equipment manufacturer, 2) availability of underlying data requirements, 3) understanding of historical data limitations, 4) results from the 2021-2022 impact evaluation, 5) sampling requirements needed to develop population-level metrics with a high level of precision and 6) Decision 19-08-001 approved greenhouse gas emission reduction requirements. Our sample design for this study follows an approach consistent with previous evaluations. We developed a stratified random sampling approach, with an attempted census for some sectors for 2023, given evaluation reporting deadlines, budgetary considerations, and results garnered from previous impact evaluations.

Our nonresidential sample design accounts for 1) project legacy status, 2) developer fleet designation, and 3) PBI status. We planned to evaluate all PBI projects, regardless of legacy status, and a sample of non-PBI legacy project. The nonresidential sample design was developed to:

- Develop legacy developer fleet GHG performance impacts at 90/30 or better. Given the high inter-project variability, we attempted a census for all developer PBI projects and sampled from a small subset of non-PBI projects.
- Develop population-level GHG performance impacts at the overall nonresidential sector level – along with other impact metrics like total avoided utility costs, coincident peak demand and roundtrip efficiency (RTE) – at 90/10 or better

With over 44,000 residential projects subject to evaluation, represented by over 500 unique project developers, the residential sample design requires a far more robust stratified random sampling approach than the nonresidential sector. Our proposed design accounts for many of the program summaries presented in Section 2 and includes stratification by 1) two upfront payment year categories (2018-2022 and 2023), 2) equipment manufacturer, 3) program budget category, and 4) program administrator.

Data processing and validation steps were performed on all metered data Verdant received as part of this impact evaluation. Sample sizes were developed to ensure SGIP population impacts were estimated at high levels of confidence and precision, and with an understanding that metering data acquisition systems are not perfect. Data attrition occurs when Verdant receives unverifiable metered data – either from partial or wholly missing metered values or data anomalies that one would not expect from energy storage performance (an example of this is a project roundtrip efficiency of greater than 100%). This section summarizes the sample design discussed previously and presents the final achieved sample for each of the energy storage customer sectors after a rigorous QA/QC process was completed.

Table C-1 presents the population and achieved sample design for the nonresidential sector. Each is presented by project Legacy status and fully qualified state, for the four PAs, as well as at the statewide level. While there is inter-segment variability, achieved sample sizes range from 69% to 100% by project count. Overall, data were collected and analyzed for 1,211 nonresidential projects (78% of all nonresidential projects in the population). The sample achieved is slightly greater as a percentage of program capacity. Achieved sample sizes range from 52% to 100% by program capacity – with 79% of the MWh of the nonresidential program represented.

TABLE C-1: 2023 ACHIEVED SAMPLE DESIGN FOR NONRESIDENTIAL POPULATION

Sector	PBI	Legacy	N	Achieved n	% of Total Sampled	N MWH	n MWH	% MWH Sampled
Nonresidential	PBI	Legacy	501	438	87%	331	288	87%
	Non-PBI	Legacy	715	491	69%	209	109	52%
	PBI	Non-Legacy	343	281	82%	343	303	89%
	Non-PBI	Non-Legacy	1	1	100%	0	0	100%
Total			**1,560**	**1,211**	**78%**	**882**	**701**	**79%**

Table C-2 provides the achieved sample design for the residential sector. Population and achieved samples are presented for upfront payment year grouping, along with a statewide total. Achieved sample sizes represent roughly 5% of total program count and MWh of capacity.

TABLE C-2: 2023 ACHIEVED SAMPLE DESIGN FOR RESIDENTIAL POPULATION

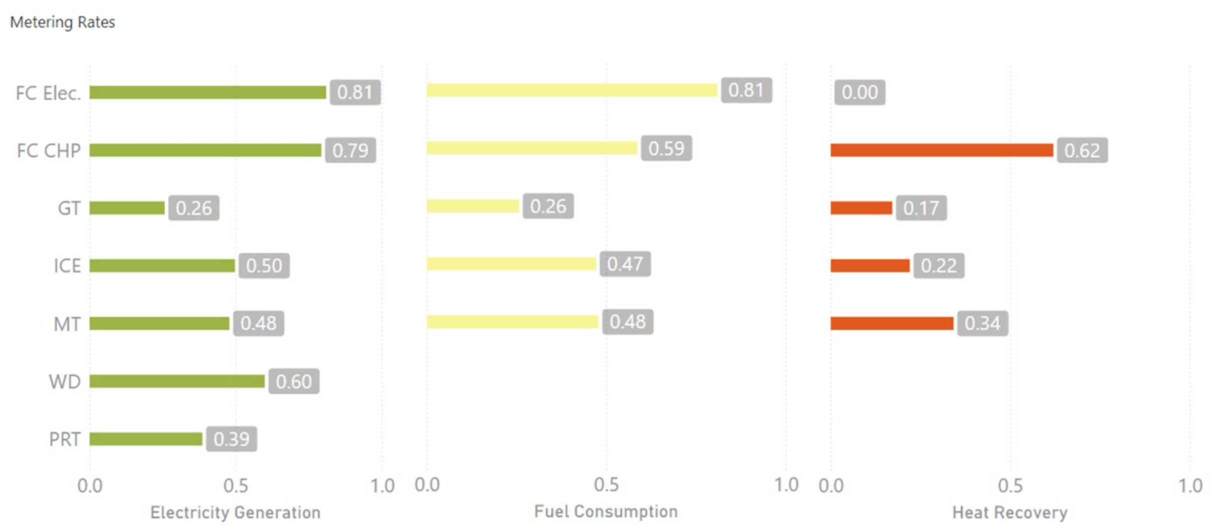
Sector	Payment Year Grouping	N	Achieved n	% of Total Sampled	N MWH	n MWH	% MWH Sampled
Residential	2017 and Prior	394	0	0%	4	0	0%
	2018-2022	35,008	1,822	5%	661	39	6%
	2023	8,895	255	3%	179	5	3%
Total		**44,297**	**2,077**	**5%**	**845**	**44**	**5%**

C.2 GENERATION

For the generation population, the approach was simple; due to the small size of the generation population in comparison to the overall program, the evaluation team attempted a census of the generation population. The first step was to download metered data for all projects still receiving PBI payment, from the Energy Solutions portal. For the remaining projects with no PBI data, the team reached out to every customer or project developer to request either metered performance data during 2021 and 2023, or in the absence of the data, to attempt to understand whether the system was performing normally, had major downtimes, was offline completely, or was decommissioned and removed from the facility. We were able to collect data from 293 out of the 365 total generation projects within the 2023 population.

Metering rates for generation equipment, for each of the different data types (electrical generation, fuel consumption, and heat recovery) are provided below in Figure C-2. The metering rate is defined as the number of hours for each project during the year with metered data divided by the total number of hours per year that the equipment is within its permanency period. For example, if a project exited its permanency period halfway through the year, the total number of hours for that project would reflect the date it was no longer within its permanency period. These metering rates are unweighted and do not reflect the relative importance of metering large projects. They are based only on projects that are still operational.

FIGURE C-2: GENERATION METERING RATES



For generation projects, missing values (either due to gaps in metered data or unavailable project data) are estimated using the findings from previous operations status surveys, ratio estimation, and adjustment using results of regression analysis of historical data.

The estimation approach used for CHP fuel cells was dictated largely by the fact that meter data for older projects and smaller projects taking capacity-based incentives was much harder to gather than data for newer and larger projects. However, our team has been evaluating this program since its inception, and metered data collected during prior evaluations was available for many older projects. To estimate 2023 impacts for unmetered CHP fuel cells, 2023 metered data available for PBI projects were used in a ratio analysis to estimate initial impact estimates. Results from the regression analysis of historical metered data were used to develop Age (A) and Incentive Design (I) adjustment factors for older PBI and non-PBI projects. The general approach is represented by the equation below.

$$Final\ Estimate = Ratio\ Estimate \times I \times A$$

EQUATION C-1

Regression analysis of metered data collected for past years was used to develop adjustment factors that were applied to initial impact estimates from the ratio analysis. The ratio analysis was performed using metered 2023 data for PBI projects. The purpose of the adjustment factors was to account for systematic performance differences due to system age (A) and incentive design (I) when estimating 2023 impacts for unmetered CHP fuel cell projects.

For each technology type, the regression analysis yields a prediction model for annual capacity factor of the general form:

$$\widehat{CF} = \widehat{\beta_0} + \widehat{\beta_1} age + \widehat{\beta_2} incentive$$

EQUATION C-2

Where:

$\widehat{CF}$	=	predicted annual capacity factor
age	=	age of system in years
$incentive$	=	indicator variable equal to 1 when incentive design is non-PBI, 0 otherwise

The regression models were used to calculate system age (A) and incentive design (I) adjustment factors for each unmetered system as:

$$A = \frac{Predicted\ CF\ for\ older\ system\ (e.g.,7\ years)}{\begin{array}{c}Predicted\ CF\ for\ system\ with\ age\\ corresponding\ to\ initial\ impacts\ estimates\end{array}}$$

EQUATION C-3

$$I = \frac{Predicted\ CF\ for\ non-PBI\ system}{\begin{array}{c}Predicted\ CF\ for\ system\ with\ incentive\ design\ (i.e.,PBI)\\ corresponding\ to\ initial\ impacts\ estimates\end{array}}$$

EQUATION C-4

Ratio estimation was used to calculate initial estimates of hourly performance for periods where observations would otherwise contain missing values. The premise of ratio estimation is that the performance of unmetered projects (projects outside the sample or projects in the sample with gaps in metered data) can be estimated from projects with metered data using a ratio estimator and an auxiliary variable. The ratio estimator is calculated from the metered sample and the auxiliary variable is used to apply the estimator to the unmetered portion of the backbone. Table C-3 summarizes the characteristics of the ratio estimation.

TABLE C-3: RATIO ESTIMATION PARAMETERS

Variable Estimated	Ratio Estimator	Auxiliary Variable	Stratification
Electricity Generation [kWh]	Capacity Factor [kWh/kW·hr]	Rebated Capacity [kW]	Hourly, by tech. type, incentive, size category, fuel type, and PA.
Fuel Consumption [MBtu]	Electrical Conversion Efficiency [unitless]	Electricity Generation [kWh]	Annual, by technology
Useful Heat Recovered [MBtu]	Useful Heat Recovery Rate [MBtu/kWh]	Electricity Generation [kWh]	Annual, by technology

The outcome of the ratio estimation process is a complete hourly impacts time series for 2023 where meter data gaps are filled with initial estimates of electricity generation, fuel consumption, and useful heat recovery. To calculate final estimates for fuel cells and wind turbines, these initial estimates were adjusted as described above.

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APPENDIX D GREENHOUSE GAS IMPACTS ESTIMATION METHODOLOGY

This section describes the methodology used to estimate the impacts on greenhouse gas (GHG) emissions from the operation of Self-Generation Incentive Program (SGIP) projects. The GHGs considered in this analysis are limited to carbon dioxide (CO_2) and methane (CH_4), as these are the two primary pollutants that are potentially affected by the operation of SGIP projects.

Hourly GHG impacts are calculated for each SGIP project as the difference between the GHG emissions under observed conditions and assumed counterfactual baseline conditions. Baseline GHG emissions are those that would have occurred in the absence of the SGIP project. SGIP storage projects change the timing of demand for electricity from power plants. Because GHG emission rates from power plants vary, this shifting of electricity demand by storage projects changes the total quantity of emissions. SGIP generation projects displace baseline GHG emissions by satisfying site electric loads as well as heating/cooling loads, in some cases. SGIP generation projects fueled with biogas may reduce emissions of CH_4 in cases where venting of the biogas directly to the atmosphere would have occurred in the absence of the SGIP project.

The calculation of GHG impacts in terms of CO_2 equivalent (CO_2eq)[1] by date and time (hereafter referred to as "hour") is summarized byEquation D-1.

$$\Delta GHG_{i,h} = sgipGHG_{ih} - enoPP_{ih} - basePPchlr_{ih} - baseBlr_{ih} - baseBio_{ih}$$ **EQUATION D-1**

Negative GHG impacts (*ΔGHG*) indicate reduction in GHG emissions. Other terms in the equation represent SGIP system emissions (*sgipGHG*), power plant emissions (*enoPP*), baseline emissions associated with operations of heating and cooling equipment (*basePPchlr, baseBlr*), and baseline emissions associated with biogas (*baseBio*). Not all SGIP projects include all of the above variables. Inclusion is determined by the SGIP distributed generation technology and fuel type. For energy storage systems the equation simplifies to Equation D-2.

$$\Delta GHG_{i,h} = -enoPP_{ih}$$ **EQUATION D-2**

1 Carbon dioxide equivalency describes, for a given mixture and amount of greenhouse gas, the amount of CO_2 that would have the same global warming potential (GWP), when measured over a specific time period (100 years). This approach must be used to accommodate cases where the assumed baseline is venting of CH_4 to the atmosphere directly.

Detailed explanations of each of the equation terms are provided below.

SGIP Generation System GHG Emissions (*sgipGHG*)

For generation projects utilizing natural gas or renewable biogas fuel, GHGs are released by the SGIP system.

SGIP emission rates for SGIP projects that use natural gas fuel were calculated as:

$$sgipGHG_{ih} = Fuel_{ih} \times \frac{1ft^3 CH_4}{935\ Btu} \times \frac{1lbmole\ CH_4}{379\ ft^3} \times \frac{1lbmole\ CO_2}{1lbmole\ CH_4} \times \frac{44lbs\ CO_2}{1lbmole\ CO_2} \times \frac{1\ metric\ ton\ CO_2}{2{,}205\ lbs\ CO_2} \qquad \textbf{EQUATION D-3}$$

SGIP emission rates for SGIP projects that use renewable biogas fuel were calculated as:

$$sgipGHG_{ih} = eno_{ih} \times \frac{3412\ Btu}{kWh} \times \left(\frac{1}{EFF_T}\right) \times \frac{1lbmole\ CH_4}{379\ ft^3} \times \frac{1lbmole\ CO_2}{1lbmole\ CH_4} \times \frac{44lbs\ CO_2}{1lbmole\ CO_2} \times \frac{1\ metric\ ton\ CO_2}{2{,}205\ lbs\ CO_2} \qquad \textbf{EQUATION D-4}$$

Where:

$sgipGHG_{ih}$	=	CO_2 emitted by SGIP project *i* during hour *h* [Metric ton/hr]
$Fuel_{ih}$	=	fuel consumption of SGIP project *i* during hour *h* [Btu]
eno_{ih}	=	electrical net output of SGIP project *i* during hour *h* [kWh]
EFF_T	=	measured electrical efficiency of technology T (see Table D-1). [Dimensionless fractional efficiency]

TABLE D-1: ELECTRICAL EFFICIENCY BY TECHNOLOGY TYPE USED FOR GHG EMISSIONS CALCULATION

	Electrical Efficiency [Eff_T]
Fuel Cell Electric	0.52
Fuel Cell CHP	0.29
Internal Combustion Engine	0.34
Microturbine	0.28
Gas Turbine	0.36

* Based on the lower heating value (LHV) metered data collected from SGIP projects

Central Station Electric Power Plant GHG Emissions (enoPP)

This section describes the methodology used to calculate impacts on CO_2 emissions from electric power plants. The methodology involves combining emission rates (in metric tons of CO_2 per kWh of electricity generated) that are service territory- and hour-specific with information about the magnitude and timing of SGIP system operation.

The service territory of the SGIP project is considered in the development of emission rates by accounting for whether the site is located in Pacific Gas and Electric's (PG&E's) territory (northern California) or in Southern California Edison's (SCE's) or Center for Sustainable Energy's (CSE's) territory (southern California). Variations in climate and electricity market conditions have an effect on the demand for electricity. This in turn affects the emission rates used to estimate the avoided CO_2 release by central station power plants. Lastly, timing of electricity generation affects the emission rates because the mix of high and low efficiency plants differs throughout the day. The larger the proportion of low efficiency plants used to generate electricity, the greater the avoided CO_2 emission rate.

The GHG Signal calculated by WattTime is used for estimating GHG impacts of SGIP systems. The CPUC-approved methodology that WattTime uses to calculate the GHG Signal assumes:

- The emissions of CO_2 from a conventional power plant depend upon its heat rate, which in turn is dictated by the plant's efficiency, and
- The mix of high and low efficiency plants in operation is reflected in the price and demand for electricity at that time.

The premise for hourly CO_2 emission rates calculated by WattTime is that the marginal power plant relies on natural gas to generate electricity. Variations in the price of electricity reflect the market demand for electricity. As demand for electricity increases, all else being equal, the price of electricity will rise. To meet the higher demand for electricity, utilities will have to rely more heavily on less efficient power plants once production capacity is reached at their relatively efficient plants. This means that during periods of higher electricity demand, there is increased reliance on lower efficiency plants, which in turn leads to a higher emission rate for CO_2. In other words, one can expect an emission rate representing the release of CO_2 associated with electricity purchased from the utility company to be higher during peak hours than during off-peak hours. Similarly, when prices are very low or negative, the CO_2 emission rate is assumed to be zero and implies renewable curtailment on the margin. Power plant emissions are calculated according to Equation D-5.

$$enoPP_{ih} = CO_2EF_{ih} \times eno_{ih} \times \frac{1\ MWh}{1000\ kWh}$$

EQUATION D-5

Where:

$enoPP_{ih}$	=	power plant GHG emissions impact for SGIP project *i* for hour *h* [Metric Ton CO_2/hr]

CO_2EF_{ih}	=	power plant GHG emissions per unit of electric energy for SGIP project *i* for hour *h* [Metric Ton CO_2/MWh]. Value from WattTime SGIP GHG Signal. https://sgipsignal.com/sgipmoer/ Version 2
eno_{ih}	=	electrical net output of SGIP project *i* during hour *h* [kWh/hr] For battery storage systems, negative while charging, positive while discharging. For generation systems, positive while generating electricity.

The equations used by WattTime to calculate values of CO_2EF are presented below for the sake of completeness and to provide context for the approaches used for some of the marginal costs (e.g., marginal wholesale electricity cost) discussed in Appendix F. For the impact evaluation, the CO_2EF values resulting from these equations were downloaded from an API maintained by WattTime.

First solve for Heat Rate *HR*:

$$HR\,\frac{\mathrm{Btu}}{\mathrm{kWh}} = \frac{\left(LMP\,\frac{\$}{\mathrm{MWh}} - VOM\,\frac{\$}{\mathrm{MWh}}\right)\frac{1\mathrm{MWh}}{1000\mathrm{kWh}}}{\left(GasP\,\frac{\$}{\mathrm{MMBtu}} + GasTransP\,\frac{\$}{\mathrm{MMBtu}} + EF\,\frac{\mathrm{MT\ CO2}}{\mathrm{MMBtu}}\,CapTradeP\,\frac{\$}{\mathrm{MT\ CO2}}\right)\frac{1\mathrm{MMBtu}}{1{,}000{,}000\mathrm{Btu}}} \qquad \textbf{EQUATION D-6}$$

Where:

HR Implied heat rate of marginal generator (electrical conversion efficiency of a power plant consuming natural gas)

Units: Btu / kWh

LMP Price for electricity in the wholesale real-time market

Interval: 5 minutes

Units: $ / MWh

Source: CAISO OASIS real-time 5-minute locational marginal price for utility DLAPs. From menu at:

Prices—Energy Prices — Interval Locational Marginal Prices

DLAPs as ‘NODE_ID’ values:

- DLAP_PGAE-APND
- DLAP_SCE-APND
- DLAP_SDGE-APND

VOM Variable Operating and Maintenance Costs of a natural gas plant

Units: $ / MWh

Source: 2021 Avoided Cost Calculator

GasP Price for commodity gas
Interval: Daily
Units: $ / MMBtu HHV
Source: Natural Gas Intelligence (NGI)

GasTransP Price to transport natural gas
Units: $ / MMBtu HHV
Source: 2021 Avoided Cost Calculator

EF Emissions Factor for natural gas
Value: 0.0530703704
Units: MT CO_2 / MMBtu HHV
Source: 2021 Avoided Cost Calculator

CapTradeP Price associated with cap and trade compliance
Units: $ / MT CO_2
Source: CAISO OASIS Green House Gas Allowance Price (published daily).

Emissions are directly proportional to Heat Rate *HR* and calculated as:

$$CO_2EF\,\frac{\text{MT CO2}}{\text{MWh}} = HR\,\frac{\text{Btu}}{\text{kWh}}\,\frac{\text{1MMBtu}}{\text{1,000,000Btu}}\,\frac{\text{1000kWh}}{\text{1MWh}}\,EF\,\frac{\text{MT CO2}}{\text{MMBtu}}$$

EQUATION D-7

Electric Power Plant Operations Corresponding to Electric Chiller Operation (*basePPchlr*)

An absorption chiller may be used to convert heat recovered from SGIP CHP projects into chilled water to serve buildings or process cooling loads. As absorption chillers are assumed to replace the use of electric chillers that operate using electricity from a central power plant, there are avoided CO_2 emissions associated with these cogeneration facilities. The electricity that would have been serving an electric chiller in the absence of the cogeneration system was calculated as:

$$chlrElec_{ih} = Chilller_i \times heat_{ih} \times COP \ \times effElecChlr \times \left(\frac{1tonhrCooling}{12Mbtu}\right)$$

EQUATION D-8

Where:

$chlrElec_{ih}$	=	the electricity of a power plant that would be needed to provide baseline electric chiller for SGIP CHP project *i* for hour *h* [kWh]
$Chiller_i$	=	allocation factor whose value depends on the SGIP CHP project design (i.e., heating only, heating and cooling, or cooling only), as determined from installation verification inspection reports (see Table D-2).

$heat_{ih}$	=	quantity of useful heat recovered for SGIP CHP project *i* for hour *h* from metering or ratio analysis [MBtu]
COP	=	0.6 – assumed efficiency of the absorption chiller using heat from SGIP CHP project [$Mbtu_{out}/Mbtu_{in}$]
effElecChlr	=	0.634 - assumed efficiency of the baseline new standard efficiency electric chiller [kWh/tonhr·Cooling]

TABLE D-2: ASSIGNMENT OF CHILLER ALLOCATION FACTOR

Project Design	$Chiller_i$
Heating and Cooling	0.5
Cooling Only	1
Heating Only	0

<u>Baseline GHG Emissions from Power Plant Operations for chiller operations</u>

The location- and hour-specific CO_2 emissions rate, when multiplied by the electricity requirements of a baseline chiller, estimates the hourly emissions avoided.

$$basePpChiller_{ih} = CO_2EF_{ih} \times chlrElec_{ih}$$

EQUATION D-9

Where:

$basePpChiller_{ih}$	=	the baseline power plant GHG emissions avoided due to SGIP CHP project *i* delivery of cooling services for hour *h* [Metric Ton CO_2/hr]

Boiler GHG Emissions (*baseBlr*)

A heat exchanger is typically used to transfer useful heat recovered from SGIP CHP projects to building or process heating loads. Using recovered heat in lieu of natural gas in this manner helps reduce CO_2 emissions. The equation below describes impacts of SGIP CHP projects providing heating services.

$$baseBlr_{ih} = Boiler_i \times heat_{ih} \times effHx \times \frac{1}{effBlr} \times \frac{1ft^3CH_4}{935\ Btu} \times \frac{1{,}000\ Btu}{1\ Mbtu} \times \frac{1\ lbmoleCO_2}{1lbmoleCH_4} \times \frac{44\ lbs\ CO_2}{1lbmole\ CO_2} \times \frac{1\ metric\ ton\ CO_2}{2{,}205\ lbs\ CO_2}$$

EQUATION D-10

Where:

$baseBlr_{ih}$	=	CO_2 emissions of the baseline natural gas boiler for SGIP CHP project *i* for hour *h* [Metric tons CO_2/hr]
effBlr	=	0.8 - assumed efficiency of the baseline natural boiler, based on previous cost effectiveness evaluations [$Mbtu_{out}/Mbtu_{in}$]
$Boiler_I$	=	allocation factor whose value depends on the SGIP CHP project design (i.e., heating only, heating and cooling, or cooling only), as determined from installation verification inspections report (see Table D-3).

$heat_{ih}$	=	the quantity of useful heat recovered for SGIP CHP project *i* for hour *h* from metering or ratio analysis [MBtu]
effHX	=	0.9 – assumed efficiency of the SGIP CHP project's primary heat exchanger

TABLE D-3: ASSIGNMENT OF BOILER ALLOCATION FACTOR

Project Design	$Boiler_i$
Heating and Cooling	0.5
Cooling Only	0
Heating Only	1

Biogas GHG Emissions (*baseBio*)

Distributed generation projects powered by renewable biogas carry an additional GHG reduction benefit. The baseline treatment of biogas is an influential determinant of GHG impacts for renewable-fueled SGIP projects. Baseline treatment refers to the typical fate of the biogas in lieu of use for energy purposes (e.g., the biogas could be vented directly to the atmosphere or flared).

There are two common sources of biogas found within the SGIP: landfills and digesters. Digesters in the SGIP to date have been associated with water resource recovery facilities (WRRF), food processing facilities, and dairies. Because of the importance of the baseline treatment of biogas in the GHG analysis, these facilities were contacted in 2009 to more accurately estimate baseline treatment. This resulted in the determination that venting is the customary baseline treatment of biogas for dairy digesters, and flaring is the customary baseline for all other renewable fuel sites. Baseline treatments of biogas for different biogas sources and facility types are described below.

For dairy digesters the baseline is usually to vent any generated biogas to the atmosphere. Of the approximately 2,000 dairies in California, conventional manure management practice for flush dairies[2] has been to pump the mixture of manure and water to an uncovered lagoon. Naturally occurring anaerobic digestion processes convert carbon present in the waste into CO_2 and CH_4. These lagoons are typically uncovered, so all CH_4 generated in the lagoon escapes into the atmosphere. Currently, there are no statewide requirements that dairies capture and flare the biogas, although some air pollution control districts are considering anaerobic digesters as a possible Best Available Control Technology (BACT) for

2 Most dairies manage their waste via flush, scrape, or some mixture of the two processes. While manure management practices for any of these processes will result in CH_4 being vented to the atmosphere, flush dairies are the most likely candidates for installing anaerobic digesters (i.e., dairy biogas projects).

volatile organic compounds. This information and the site contacts support a biogas venting baseline for dairies.

For other digesters, including WRRFs and food processing facilities, the baseline is not quite as straightforward. There are almost 250 WRRFs in California, and the larger facilities (i.e., those that could generate 1 MW or more of electricity) are typically required to capture and destroy methane; therefore, flaring is used as the biogas baseline.

Defining the biogas baseline for landfill gas recovery operations presented a challenge in past SGIP impact evaluations. California law requires most landfills with at least 450,000 tons of waste in place to collect and either flare or use their gas. Installation verification inspection reports and renewable-fueled distributed generation landfill site contacts verified that they would have flared their CH_4 in the absence of the SGIP. Therefore, the biogas baseline assumed for landfill facilities is flaring of the CH_4.

In CPUC Decision 09-09-048 (September 24, 2009), eligibility for renewable fuel use incentives was expanded to include “directed biogas” projects. Deemed renewable fuel use projects, directed biogas projects were eligible for higher incentives under the SGIP. Directed biogas projects purchased biogas fuel that is produced at another location. The procured biogas was processed, cleaned-up, and injected into a natural gas pipeline for distribution. Although the purchased gas was not likely to be delivered and used at the SGIP renewable fuel use project, directed biogas projects were treated as renewable fuel use projects for GHG impacts purposes.

All directed biogas projects included in the 2023 impacts evaluation have met their contractual procurement requirements for biogas and are assumed to no longer procure renewable fuel. For GHG impacts purposes these projects were assumed to use natural gas during 2023. The requirements lasted five years after the upfront payment date for PY10 and earlier projects, and 10 years after the upfront payment date for PY11 and later projects.

GHG Emissions of Flared Biogas

Methane is naturally created in landfills, wastewater treatment plants, and dairies. If not captured, the CH_4 escapes into the atmosphere contributing to GHG emissions. Capturing the CH_4 provides an opportunity to use it as a fuel. When captured CH_4 is not used to generate electricity or satisfy heating or cooling loads, it is burned in a flare.

In situations where flaring occurs, baseline GHG emissions comprise CO_2 only. The flaring baseline was assumed for the following types of biogas projects:

- Facilities using digester gas (with the exception of dairies),

- Landfill gas facilities, and

The assumption is that the flaring of CH_4 would have resulted in the same amount of CO_2 emissions as occurred when the CH_4 was captured and used in the SGIP project to produce electricity.

$$baseBio_{ih} = sgipGHG_{ih}$$

EQUATION D-11

GHG Emissions of Vented Biogas

Methane capture and use at renewable fuel use facilities where the biogas baseline is venting avoids release of CH_4 directly into the atmosphere. The venting baseline was assumed for all dairy digester SGIP projects. Biogas consumption is typically not metered at SGIP projects. Therefore, CO_2eq emission rates were calculated by assuming an electrical efficiency.

$$baseBio_{ih} = eno_{ih} \times \frac{3412\ Btu}{kWh} \times \frac{1}{EFF_T} \times \frac{1 ft^3 CH_4}{935\ Btu} \times \frac{1 lbmole CH_4}{379\ ft^3 CH_4} \times \frac{16 lbs CH_4}{lbmole CH_4} \times \frac{1\ metric\ ton}{2{,}205\ lbs} \times \frac{21\ metric\ tons\ CO_2}{1\ metric\ ton\ CH_4}$$

EQUATION D-12

Where:

$baseBio_{ih}$	=	CO_2eq emissions of the baseline methane emissions for SGIP CHP project *i* for hour *h* [Metric tons CO_2/hr]
EFF_T	=	electrical efficiency of technology T (see Table D-1)

APPENDIX E ELECTRIC UTILITY AVOIDED COSTS

Evaluation of SGIP impacts includes impacts on electric utility costs. These impacts are not measured directly. Information from secondary sources is incorporated to estimate these impacts. The approach used to estimate electric utility avoided costs is described in this appendix. Key data sources are summarized below.

E3 Avoided Cost Calculator (ACC). ACC forecasts of distribution capacity costs, transmission capacity costs, and generation capacity costs were included in the impacts evaluation. The ACC is primarily used as a planning tool rather than for impacts evaluation, as it contains 31-year forecasts (2022-2052) for costs and emissions. The forecasts are based on assumed, typical weather and market conditions. However, these forecasts are suitable for estimating marginal avoided costs of the three capacity costs due to the long-term nature of capacity expansion. Additionally, assumptions from the ACC are incorporated into calculation of the GHG Signal (see Appendix D), as well as into several cost components as described below.

CAISO Real-Time Locational Marginal Price Data (RT-LMP). Real-time LMPs serve as the measure of marginal electric energy prices in the impacts evaluation in order to maintain consistency with the GHG Signal and estimates of GHG impacts. In the RT-LMP data, Energy costs and GHG Cap & Trade costs are bundled together and reported as the 'Energy' price. To maintain consistency with ACC methods, the RT-LMP values are separated into Energy and GHG components.

SGIP GHG Signal. Values of the GHG Signal are used to estimate Cap & Trade costs. Data sources for the GHG signal include the ACC and CAISO data (see Appendix D for detailed description of GHG Signal).

Each of the components of electric utility marginal costs is described below.

E.1 ENERGY

$$Energy\frac{\$}{\mathrm{MWh}} = LMP - CO_2EF \times CapTradeP$$

EQUATION E-1

Where:

Energy Portion of marginal total electricity price *LMP* (including GHG cap & trade) attributable to power plant fuel and operations, and not attributable to cap & trade costs

Units: $ / MWh

LMP Real-time locational marginal price of electricity

Units: $ / MWh

Source: CAISO OASIS

CO_2EF Marginal power plant GHG emissions factor

Units: $ / MWh

Source: https://sgipsignal.com/sgipmoer/ Version 2

CapTradeP Marginal cost of compliance with the California Air Resources Board's cap-and-trade system.

Units: $ / MT CO2

Source: CAISO OASIS GHG allowance daily price

E.2 GHG CAP & TRADE

$$GHGcapTrade\,\frac{\$}{\mathrm{MWh}} = CO_2EF\,\frac{\mathrm{MT\ CO2}}{\mathrm{MWh}} \times CapTradeP\,\frac{\$}{\mathrm{MT\ CO2}} \times LossRate$$ **EQUATION E-2**

Where:

GHGcapTrade Portion of total CAISO locational marginal energy price (including GHG) attributable to GHG Cap & Trade

Units: $ / MWh

LossRate Electricity distribution loss factor

Value: 1.0724

Units: Dimensionless

Source: 2022 ACC, Sheet 'Losses', Cells R8:R8766

E.3 LOSSES

$$Losses\,\frac{\$}{\mathrm{MWh}} = Energy \times (LossRate - 1)$$ **EQUATION E-3**

Where:

Losses Electrical losses

Units: $ / MWh

E.4 GHG ADDER

$$GHG_{adder}\frac{\$}{\text{MWh}} = CO_2EF\frac{\text{MT CO2}}{\text{MWh}} \times GHG_{adder\_fc}\frac{\$}{\text{MT CO2}} \times LossRate \qquad \textbf{EQUATION E-4}$$

Where:

GHG_{adder} The non-monetized carbon price beyond the cost of cap-and-trade allowances, reflecting the cost of further reducing carbon emissions

Units: $ / MWh

GHG_{adder_fc} GHG Adder Price Forecast

Value: 2023 = 8.6015

Units: $ / MT CO_2

Source: 2022 ACC, Sheet 'Emissions', Cells R13:S13

E.5 GHG PORTFOLIO REBALANCING

$$GHG_{rebalancing}\frac{\$}{\text{MWh}} = -CI\frac{\text{MT CO2}}{\text{MWh}} \times GHGadderP\frac{\$}{\text{MT}} \times LossRate \qquad \textbf{EQUATION E-5}$$

Where:

$GHG_{rebalancing}$ Result of utility resource plan adjustments for added distributed energy resources and achievement of annual emissions intensity targets

Units: $ / MWh

CI Allowable carbon intensity

Value: 2023 = 0.17120

Units: MT CO_2 / MWh

Basis: Nominal $US

Source: 2022 ACC, Sheet 'Emissions', Cell T21

E.6 ANCILLARY SERVICES

$$AncillarySrvcs\frac{\$}{\text{MWh}} = Energy \times ASfactor \qquad \textbf{EQUATION E-6}$$

Where:

AncillarySrvcs Ancillary services costs

Units: $ / MWh

ASfactor Ancillary services factor (as fraction of Wholesale Energy)

Value: 2023 = 0. 002261

Units: Dimensionless
Source: 2022 ACC, Sheet 'AS Procurement', Cells F4

E.7 METHANE LEAKAGE

$$MethaneLeakage = (CO_2EF \times GHG_{total} - CI \times GHG_{adder}) \times LeakRate \times LossRate$$ **EQUATION E-7**

Where:

MethaneLeakage Cost of methane leakage
Units: $ / MWh

LeakRate Upstream in-state methane leakage factor (as fraction of Wholesale Energy)
Value: 0.0557
Units: Dimensionless
Basis: 100-year active GWP time horizon
Source: 2022 ACC, Sheet 'Methane Leakage', Cell C4

And:

$$GHG_{total}\frac{\$}{\mathrm{MT}} = CapTradeP + GHG_{adder\_fc}$$ **EQUATION E-8**

Where:

GHG_{total} New Total GHG Value
Units: $ / MT

E.8 GENERATION, DISTRIBUTION, AND TRANSMISSION CAPACITY

The estimation of marginal costs of generation, distribution, and transmission capacity is a long-term planning undertaking that is fundamentally different from estimation of marginal costs such as Energy or Cap & Trade, for which transparent and immediate markets exist to satisfy real-time demands. As no alternatives to the ACC are readily available, values from the ACC are used for SGIP impacts evaluation. They are not used directly however, because the values in the ACC are based on typical meteorological year weather. To align the cost values with weather actually observed during 2023 the values from the

ACC were rank ordered prior to merging into the SGIP data. In the resulting data set, the highest capacity costs from the ACC are assigned to the hours when actual 2023 grid loads were highest.

E.9 SUMMARY

Final sources of data for evaluation of SGIP 2023 electric utility marginal cost impacts are summarized in the table below.

Cost Element	**Data Sources for SGIP Impacts Evaluation**
Energy	CAISO for Energy (with GHG)
GHG Cap & Trade	CAISO GHG Allowance
GHG Adder	ACC for GHG Adder Factor
GHG Rebalancing	ACC for Carbon Intensity Factor
Ancillary Services	ACC for constants, CAISO for Energy (with GHG), SGIP GHG Signal for emissions
Losses	
Methane Leakage	ACC for constants, SGIP GHG Signal for emissions
Generation Capacity	2022 ACC Data for 2023 Rank-ordered based on CAISO DLAP grid loads
Transmission Capacity	
Distribution Capacity	